VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

June 27, 2019

10 CFR 50
10 CFR 51
10 CFR 54

United States Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D.C. 20555-0001

Serial No.: 19-269
NRA/DEA: R2
Docket Nos.: 50-280/281
License Nos.: DPR-32/37

VIRGINIA ELECTRIC AND POWER COMPANY
SURRY POWER STATION (SPS) UNITS 1 AND 2
SUBSEQUENT LICENSE RENEWAL APPLICATION
RESPONSE TO REQUESTS FOR ADDITIONAL INFORMATION – SET 1

By letter dated October 15, 2018 (Agencywide Documents Access and Management System (ADAMS) Package Accession No. ML18291A842), Virginia Electric and Power Company (Dominion Energy Virginia or Dominion) submitted an application for the subsequent license renewal of Renewed Facility Operating License Nos. DPR-32 and DPR-37 for Surry Power Station (SPS) Units 1 and 2, respectively.

The NRC has been reviewing the SPS Subsequent License Renewal Application (SLRA) and has identified areas where additional information is needed to complete their review. In an email from Emmanuel Sayoc, NRC, to Paul Aitken, Dominion, dated May 30, 2019, the NRC provided specific requests for additional information (RAIs) to support their review of the SLRA. Dominion's response to the NRC RAIs is provided in Enclosures 1, 2 and 3.

Enclosure 2, which includes the response to RAI 4.7.3-2 and 4.7.3-3, contains information proprietary to Westinghouse Electric Company LLC ("Westinghouse"). A redacted, non-proprietary version of the information is provided in Enclosure 3. Enclosure 1 contains the response to the remaining RAIs.

Since Enclosure 2 contains information proprietary to Westinghouse, it is supported by an Affidavit signed by Westinghouse, the owner of the information in Enclosure 4. The Affidavit sets forth the basis on which the information may be withheld from public disclosure by the Nuclear Regulatory Commission ("Commission") and addresses with specificity the considerations listed in paragraph (b)(4) of Section 2.390 of the Commission's regulations. Accordingly, it is respectfully requested that the information which is proprietary to Westinghouse be withheld from public disclosure in accordance with 10 CFR Section 2.390 of the Commission's regulations. Correspondence with

A035
NRR

Enclosure 2 contains information that is being withheld from public disclosure under 10 CFR 2.390.
Upon separation from Attachment 2, this letter is decontrolled.

respect to the copyright or proprietary aspects of the items listed above or the supporting Westinghouse Affidavit should reference CAW-19-4897 and should be addressed to Camille T. Zazula, Manager, Infrastructure & Facilities Licensing, Westinghouse Electric Company, 1000 Westinghouse Drive, Suite 165, Cranberry Township, Pennsylvania 16066.

Enclosure 5 provides mark-ups of affected SLRA sections and/or tables associated with RAI Set 1. It should be noted that changes to four commitments (Items #11, #20, #27 and #28) are provided in Table A4.0-1.

If you have any questions or require additional information regarding this submittal, please contact Mr. Paul Aitken at (804) 273-2818.

Sincerely,

Mark D. Sartain
Vice President – Nuclear Engineering & Fleet Support

COMMONWEALTH OF VIRGINIA)
)
COUNTY OF HENRICO)

The foregoing document was acknowledged before me, in and for the County and Commonwealth aforesaid, today by Mark D. Sartain, who is Vice President - Nuclear Engineering & Fleet Support of Virginia Electric and Power Company. He has affirmed before me that he is duly authorized to execute and file the foregoing document in behalf of that Company, and that the statements in the document are true to the best of his knowledge and belief.

Acknowledged before me this 27 day of June, 2019.

My Commission Expires: March 31, 2022

Diane E. Aitken
Notary Public

DIANE E. AITKEN
NOTARY PUBLIC
REG. #7763114
COMMONWEALTH OF VIRGINIA
MY COMMISSION EXPIRES MARCH 31, 2022

Commitments made in this letter: None

Enclosures:

1. Response to Requests for Additional Information - Set 1 Regarding SPS SLRA
2. Proprietary Response to RAIs 4.7.3-2 and 4.7.3-3 - Set 1 Regarding SPS SLRA
3. Non-proprietary Response to RAIs 4.7.3-2 and 4.7.3-3 - Set 1 Regarding SPS SLRA
4. CAW-19-4897, Westinghouse Affidavit for Withholding Proprietary Information, dated June 4, 2019
5. SLRA Mark-ups – Set 1 RAIs

cc: (w/o Enclosures except *)

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Enclosure 1

RESPONSE TO REQUESTS FOR ADDITIONAL INFORMATION SET 1 REGARDING SPS SLRA

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

RESPONSE TO REQUESTS FOR ADDITIONAL INFORMATION SET 1 REGARDING SPS SLRA

By letter dated October 15, 2018 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML18291A842), as supplemented by letters dated January 29, 2019 (ADAMS Accession No. ML19042A137), and April 2, 2019 (ADAMS Accession No. ML19095A666), Virginia Electric and Power Company (Dominion Energy Virginia or Dominion) submitted to the U.S. Nuclear Regulatory Commission (NRC or staff) an application to renew the Renewed Facility Operating License Nos. DPR-32 and DPR-37 for the Surry Power Station, Unit Nos. 1 and 2. Dominion submitted the application pursuant to Title 10 of the *Code of Federal Regulations* Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," for subsequent license renewal.

From April 3, 2019 through May 15, 2019, the U.S Nuclear Regulatory Commission (NRC) staff sent Dominion the draft Requests for Additional Information (RAIs) for various technical review packages (TRP). Dominion subsequently informed the NRC staff that clarification calls were needed to discuss the information requested. Between April 11, 2019 through May 30, 2019, clarification calls were completed for the draft RAIs unless it was determined that a clarification call was not required. The final RAIs resulting from these calls and Dominion's responses are provided below. For clarity, the order of the RAI responses is consistent with the SLRA order format as opposed to the TRP reference used in the RAI.

RAI 3.2.2.1.1-1

Background:

GALL-SLR Report item S-454 recommends that cracking be managed as an aging effect for copper alloy greater than 15 percent zinc components exposed to air or condensation.

There are many SLRA Table 2 items that state that copper alloy greater than 15 percent zinc components exposed to air-indoor uncontrolled have no aging effects. SLRA Change Notice No. 1, (ADAMS Accession No. ML19042A137) states:

- *"[t]he air-indoor uncontrolled environment is assigned to components that are uninsulated, or not exposed to condensation."*

- *"[c]racking of copper alloy >15% Zn in air is not expected in the absence of wetting and ammonia contaminants, which are not present in the air-indoor uncontrolled environment."*

Issue:

A basis has not been provided for why ammonia compounds are not present in the air-indoor uncontrolled environment. For example, if ammonia compounds are present in insulation installed on an in-scope pipe or one that is not in-scope and packing leakage or gasket leaks were to occur, ammonia compounds could be transported to the surface of in-scope components constructed from copper alloy greater than 15 percent zinc. Depending on the concentration of the ammonia compounds, this could result in cracking. This is consistent with NUREG-2221, which states:

> *Based on a review of ASM Handbook, Volume 13B, "Corrosion: Materials, Corrosion of Copper and Copper Alloys," ASM International, 2006, pages 129 – 133, the staff concluded that copper alloy (>15% Zn or >8% Al) is susceptible to cracking due to SCC in air or condensation environments depending on the presence of ammonia-based compounds. In addition to being present in the outdoor air environment, they could be conveyed to the surface of a copper alloy (>15% Zn or >8% Al) component via leakage through the insulation from bolted connections (e.g., flange joints, valve packing).*

Request:

State the basis for why there are no more than trace amounts of ammonia compounds in the vicinity of in-scope components. If there are more than trace amounts of ammonia compounds in the vicinity of in-scope piping, state the basis for why cracking is not considered an applicable aging effect for components constructed from copper alloy greater than 15 percent zinc and exposed to air-indoor uncontrolled.

Dominion Response:

With the exception of the containment spray / recirculation spray system spray ring nozzles, which are mounted near the top of the Containment structures and therefore not susceptible to leakage dripping from above, Dominion will manage cracking of the copper alloy (>15% Zn) components exposed to an external environment of air-indoor uncontrolled with the *External Surfaces Monitoring of Mechanical Components* program as indicated below. The applicable SLRA Table No., NUREG-2191 Item, Table 1 Item, and Industry Standard Note is indicated for each item.

Auxiliary Systems				
SLRA Table No.	**Component**	**NUREG-2191 Item**	**Table 1 Item**	**Note**
3.3.2-4	Valve body	VII.I.A-405a	3.3.1-132	A
3.3.2-5	Valve body	VII.I.A-405a	3.3.1-132	A
3.3.2-6	Sight glass (body)	VII.I.A-405a	3.3.1-132	A
	Valve body	VII.I.A-405a	3.3.1-132	A
3.3.2-8	Sight glass (body)	VII.I.A-405a	3.3.1-132	A
3.3.2-11	Heat exchanger (air compressor seal water shell)	VII.I.A-405a	3.3.1-132	C
	Orifice	VII.I.A-405a	3.3.1-132	A
	Valve body	VII.I.A-405a	3.3.1-132	A
3.3.2-12	Strainer body	VII.I.A-405a	3.3.1-132	A
3.3.2-13	Trap body	VII.I.A-405a	3.3.1-132	A
3.3.2-18	Sight glass (body)	VII.I.A-405a	3.3.1-132	A
3.3.2-28	Filter housing (chiller supply)	VII.I.A-405a	3.3.1-132	A
	Filter housing (laboratory tank vent filter)	VII.I.A-405a	3.3.1-132	A
	Strainer body	VII.I.A-405a	3.3.1-132	A
	Tank (air chamber)	VII.I.A-405a	3.3.1-132	A
	Valve body	VII.I.A-405a	3.3.1-132	A
3.3.2-29	Valve body	VII.I.A-405a	3.3.1-132	A
3.3.2-32	Heat exchanger (seal water - channel)	VII.I.A-405a	3.3.1-132	C
	Heat exchanger (seal water - shell)	VII.I.A-405a	3.3.1-132	C

Auxiliary Systems				
SLRA Table No.	**Component**	**NUREG-2191 Item**	**Table 1 Item**	**Note**
	Valve body	VII.I.A-405a	3.3.1-132	A
3.3.2-34	Hose rack (fittings)	VII.I.A-405a	3.3.1-132	A
	Sprinkler head	VII.I.A-405a	3.3.1-132	A
	Valve body	VII.I.A-405a	3.3.1-132	A
3.3.2-36	Heat Exchanger (radiator – header)	VII.I.A-405a	3.3.1-132	C
	Orifice	VII.I.A-405a	3.3.1-132	A
	Piping, piping components	VII.I.A-405a	3.3.1-132	A
	Sight glass (body)	VII.I.A-405a	3.3.1-132	A
	Strainer body	VII.I.A-405a	3.3.1-132	A
	Valve body	VII.I.A-405a	3.3.1-132	A
3.3.2-37	Filter housing	VII.I.A-405a	3.3.1-132	A
	Filter housing (head)	VII.I.A-405a	3.3.1-132	A
	Lubricator body	VII.I.A-405a	3.3.1-132	A
	Valve body	VII.I.A-405a	3.3.1-132	A
3.3.2-38	Valve body	VII.I.A-405a	3.3.1-132	A

SLRA Table 3.3.1, Item Number 3.3.1-132 is supplemented to add air-indoor uncontrolled as an environment for copper alloy >15% Zn components managed by the *External Surfaces Monitoring of Mechanical Components* (B2.1.23) program.

Steam and Power Conversion Systems				
SLRA Table No.	**Component**	**NUREG-2191 Item**	**Table 1 Item**	**Note**
3.4.2-2	Heat exchanger	VIII.I.H.S-454	3.4.1-106	C

Steam and Power Conversion Systems				
SLRA Table No.	**Component**	**NUREG-2191 Item**	**Table 1 Item**	**Note**
	(electro-hydraulic oil – shell)			
	Valve body	VIII.I.H.S-454	3.4.1-106	A
3.4.2-5	Sight glass (body)	VIII.I.H.S-454	3.4.1-106	A
3.4.2-3	Flow indicator	VIII.I.H.S-454	3.4.1-106	A
	Sight glass (body)	VIII.I.H.S-454	3.4.1-106	A
	Valve body	VIII.I.H.S-454	3.4.1-106	A
3.4.2-8	Sight glass (body)	VIII.I.H.S-454	3.4.1-106	A
	Valve body	VIII.I.H.S-454	3.4.1-106	A
3.4.2-11	Sight glass (body)	VIII.I.H.S-454	3.4.1-106	A
	Valve body	VIII.I.H.S-454	3.4.1-106	A

SLRA Table 3.4.1, Item Number 3.4.1-106 is revised to indicate, “Consistent with NUREG-2191.”

<u>SLRA Revisions:</u>

The SLRA Table Nos. indicated above, Table 3.3.1, Item Number 3.3.1-132, and Table 3.4.1, Item Number 3.4.1-106 are revised as described above, but SLRA mark-ups have not been included in Enclosure 5 due to the voluminous amount of extraneous work it would take to show the specified changes.

<u>RAI 3.2.2.1.1-2</u>

<u>Background:</u>

During its review of some aging management items that were cited as being not applicable to the Surry units, the staff noted the following:

1. *SLRA Table 3.3-1, item 3.3.1-178, states that there are no in-scope fiberglass piping and piping components exposed to concrete in the Auxiliary Systems.*

However, UFSAR Section 9.10.4.18 states that there is fiberglass piping in mechanical equipment room number 4 (MER-4).

2. *SLRA Table 3.3-1, item 3.3.1-184, states that there is no in-scope PVC piping, piping components or tanks exposed to concrete in the auxiliary systems. However, UFSAR Table 11.2-1, "Waste Processing System Design Data," states that some portions of the liquid waste reverse osmosis unit are constructed of PVC. SLRA Section 2.3.3.23, states that some portions of the liquid waste system are in-scope.*

3. *SLRA Table 3.1-1, item 3.1.1-105, states that loss of material of steel with an external environment of concrete is not applicable to components in the reactor coolant system. SLRA Section 3.1.2.2.15 states that the steel neutron shield tanks are the only steel components exposed to concrete in the reactor coolant system. SLRA Table 3.1-1, item 3.1.1-115, states that there are no stainless steel components exposed to concrete in the reactor coolant system. However, UFSAR Section 4.1.2.9, "Reactor Coolant Pressure Boundary Surveillance," states, "[t]he reactor arrangement within the containment provides sufficient space for inspection of the external surfaces of the reactor coolant piping, except for the area of pipe within the primary shielding concrete."*

4. *SLRA Section 3.2.2.2.9 states, "[t]he concrete exposed stainless steel piping aligned to [item 3.2.1-091] is embedded within interior concrete at the containment sump and is not potentially exposed to groundwater. There are no aging effects identified that require aging management." SLRA Table 3.2.2-4 plant specific note 8 states, "[s]uction piping embedded in concrete from the containment sump is not exposed to groundwater, and has no aging effects requiring management." However, UFSAR Table 6.3-3 states that there is an outside recirculation spray pump (cited in SLRA Table 3.2-2) set in concrete. SLRA Table 3.2.2-2 includes the recirculation spray pump casing but does not cite concrete as an applicable environment.*

5. *SLRA Table 3.2.1, item 3.3.1-146, states that there are no in-scope stainless steel underground piping, piping components, and tanks in the auxiliary systems. However, UFSAR Section 9.10.2.3.2 states that the technical support center charcoal filter units are located in a service building vault. In addition, UFSAR Section 9.10.4.3 states that there are containment penetration vaults and UFSAR 9.10.4.7 states that there are outside containment penetration vaults.*

Issue:

1. *While UFSAR Section 9.10.4.18 does not conflict with item 3.3.1-178, it could be possible that the fiberglass piping in MER-4 penetrates the concrete floor.*

2. *While UFSAR Table 11.2-1 does not conflict with item 3.3.1-184, it could be possible that there could be PVC piping that penetrates the concrete floor.*

3. *While UFSAR Section 4.1.2.9 does not conflict with items 3.1.1-105 and 3.1.1-115, it could be possible that there are other steel components and stainless steel components exposed to concrete in the vicinity of the primary shielding concrete.*

4. *While UFSAR Table 6.3-3 does not conflict with SLRA Section 3.2.2.2.9 or Table 3.2.2-2, it could be possible that the recirculation spray pump casing is exposed to concrete. In addition, given the pump's location, it is possible that the concrete could be exposed to ground water.*

5. *While the UFSAR Chapter 9 references do not conflict with item 3.3.1-146, it is possible that there could be stainless steel piping, piping components, or tanks located in vaults meeting the criteria for the underground environment in the auxiliary systems.*

Request:

1. *Confirm that there are no in-scope fiberglass piping and piping components exposed to concrete in the auxiliary systems.*

2. *Confirm that there are no in-scope PVC piping and piping components exposed to concrete in the auxiliary systems.*

3. *Confirm that there are no steel components other than the neutron shield tanks nor stainless steel components exposed to concrete in the reactor coolant system.*

4. *State whether the recirculation spray pump casing is exposed to concrete. If it is exposed to concrete, state whether the concrete could be exposed to ground water.*

5. *Confirm that there are no in-scope stainless steel underground piping, piping components, and tanks in the auxiliary systems.*

Dominion Response:

Response to RAI 3.2.2.1.1-2, Request 1:

A walkdown of the MER-4 area confirmed that fiberglass piping in this area is not embedded in concrete. Review of fiberglass piping in other locations has not identified any fiberglass embedded in concrete in the auxiliary systems.

Response to RAI 3.2.2.1.1-2, Request 2:

No portion of the "RF Liquid Waste Reverse Osmosis Unit" described in UFSAR Table 11.2-1 is within scope. That equipment is part of the Radwaste Facility Liquid Waste system, which is not the same as the Liquid and Solid Waste system described in SLRA Section 2.3.3.23), and is located in the Radwaste Facility, which does not contain any safety-related equipment. Review of PVC components in other locations has not identified any PVC embedded in concrete in the auxiliary systems.

Response to RAI 3.2.2.1.1-2, Request 3:

The neutron shield tank outer wall is the only reactor coolant system component exposed to concrete.

Response to RAI 3.2.2.1.1-2, Request 4:

The recirculation spray pump casings are not exposed to concrete. The recirculation spray pumps are described as the vertical deep-well type in UFSAR Section 6.3.1.3.2. The outside recirculation spray pumps are located within stainless steel wells connected to the sump by embedded piping and the inside recirculation spray pumps are located within wells within the sump. The wells are encased within the containment concrete (not potentially exposed to groundwater), and are considered part of the structure. The well lining is evaluated as an extension of the containment sump liner. The pump casing itself is located inside the well. The metallic components of the wells do not exit the concrete into soil.

Response to RAI 3.2.2.1.1-2, Request 5:

The Technical Support Center charcoal filter housing is non-safety-related, contains no fluids, and is not credited with support of safety-related functions or regulated events. The filter housing is not within scope, and is accessible. The penetration vaults addressed in UFSAR Sections 9.10.4.3 and 9.10.4.7 are normally accessible areas. Review of other systems confirms that there are no stainless steel underground piping, piping components, and tanks in the auxiliary systems.

RAI 4.1-1

Background:

In Section 4.1 of the subsequent license renewal application (SLRA) for Surry Power Station (SPS), Units 1 and 2, the applicant provides the results of its TLAA and regulatory exemptions searches that were performed to comply with the requirements specified in 10 CFR 54.21(c)(1) and (c)(2). The applicant states that it did not identify any regulatory exemptions currently in effect that were granted in accordance with 10 CFR 50.12 and are based on a TLAA.

In Section 4.1.3 of NUREG-2192 (SRP-SLR Report), the staff identifies that regulatory exemptions granting permission for use of ASME Code Case N-514 as an alternative PWR low temperature overpressure protection (LTOP) system setpoint methodology is an example of a regulatory exemption that has been granted in accordance with 10 CFR 50.12 and is based on a TLAA. By letter and safety evaluation dated October 31, 1995 (Refer to ADAMS Legacy Library Accession No. 9512140231, Microfiche Address No. 86532, Fiche Pages 294 – 301), the staff granted Dominion a regulatory exemption (under the requirements in 10 CFR 50.12) that permitted ASME Code Case N-514 to be used as part of the methods that would be used to establish the LTOP system setpoints for the licensing basis (i.e., the basis for the LTOP system setpoint analysis is established in WCAP-14040, Revision 4, which is relied on as part of the CLB and invokes use of Code Case N-514 for the LTOP system setpoint analysis).

Issue:

The exemption granting permission for use of Code Case N-514 may qualify as a regulatory exemption that meets the criteria in 10 CFR 54.21(c)(2) because: (a) the exemption was granted on October 31, 1995, in accordance with the requirements in 10 CFR 50.12, (b) selection of the pressure lift and system enable temperature setpoints for the LTOP systems using the Code Case methodology may be dependent on the results of the adjusted reference temperature analysis (i.e., 1/4T RTNDT analysis) or pressure-temperature analyses for the facility (which are TLAAs), and (c) application of the Code Case may have been used for or carried over as the basis for the current LTOP system setpoints for 48 effective full power years (i.e., the exemption remained in effect for the establishment of the current LTOP setpoints).

Request:

Provide the basis why the October 31, 1995, regulatory exemption permitting use of ASME Code Case N-514 (as granted in accordance with 10 CFR 50.12) is not considered to be a regulatory exemption that remains in effect and is based on [a TLAA].

Dominion Response:

Dominion Energy confirms that a regulatory exemption to use ASME Code Case N-514 is not required for Surry Subsequent License Renewal (SLR).

The provisions of Code Case N-514 have been incorporated into later versions of Section XI of the ASME Code that have been endorsed by the NRC (e.g., 1996 version, which is approved per 10 CFR 50.55a). The Pressure – Temperature (P-T) limit curves in WCAP-18243-NP were generated for 68 effective full-power years (EFPY) using the K_{Ic} methodology detailed in the 1998 Edition through 2000 Addenda of the ASME Code, Section XI, Appendix G.

While Code Case N-514 has been incorporated into later editions of the ASME Code approved by NRC, there are limitations on its use. The provision allowing pressure during a low temperature overpressure (LTOP) event to reach 110% of the isothermal limit curve is only applicable to P-T curves based upon the K_{IR}/K_{Ia} fracture toughness curve. If the P-T curves are based on K_{Ic} fracture toughness, the pressure during a postulated LTOP event may not exceed 100% of the isothermal limit curve.

For SLR, Dominion demonstrated that maintaining the current P-T curves based on K_{IR}/K_{Ia} (and the corresponding LTOP setting) is acceptable by demonstrating that 110% of the K_{IR}/K_{Ia} curves remains lower (more conservative) than 100% of the K_{IC} based curves.

The analysis in WCAP-18243-NP relies on protecting 100% of 80-year K_{Ic}-based P-T limit curves for LTOP. WCAP-18243-NP demonstrates that the K_{Ia}-based P-T limit curves (currently in the Technical Specifications) and the corresponding LTOP setting are conservative, even when making an adjustment for 10% to account for the K_{Ia} vs. K_{Ic} fracture toughness methods.

Since Code Case N-514 is not relied upon for any portion of the analysis, Code Case N-514 is not considered to be a regulatory exemption that remains in effect for SLR.

<u>RAI 4.7.3-1</u>

<u>Background:</u>

SLRA Section 4.7.3 addresses a TLAA on leak-before break (LBB) for the reactor coolant system (RCS) primary loop. Dominion (applicant) indicated that the LBB analysis for 80 years of operation is documented in WCAP-15550, Revision 2.

Section 4.3 of WCAP-15550, Revision 2 discusses the fracture toughness properties of the piping elbows fabricated with cast austenitic stainless steel (A351 CF8M). Section 4.3 of the WCAP report also indicates that, as discussed in NUREG/CR-4513, Revision 2, the lower bound fracture toughness of thermally-aged CASS elbow is similar to that of stainless steel welds. The applicant used this general discussion regarding the lower-bound fracture toughness relationship as one of the bases for why the fracture toughness of the specific CASS elbows is bounding for the fracture toughness of the stainless steel welds in the primary loop.

Standard Review Plan (SRP; NUREG-0800) Section 3.6.3 provides the areas of review, acceptance criteria and review procedure for evaluations of LBB analyses. Specifically, SRP Section 3.6.3, Subparagraph III.11.A.(i) indicates that the applicant should provide the material properties used in the LBB analysis (e.g., toughness, tensile data, and long-term effects such as thermal aging).

<u>Issue:</u>

Section 4.3 of WCAP-15550, Revision 2 does not discuss the fracture toughness data of plant specific (or representative) primary loop stainless steel welds. The staff finds a need to confirm that the fracture toughness of the plant-specific (or representative) primary loop welds is bounded by the fracture toughness estimated for the Surry CASS elbows in accordance with NUREG/CR-4513, Revision 2. The staff also finds a similar concern related to the applicant's determination of the tensile properties of weld materials in the LBB analysis.

Even though Revision 2 of NUREG/CR-4513 uses the latest fracture toughness data of thermally-aged CASS materials, the GALL-SLR Report includes a reference to NUREG-4513/CR, Revision 1 rather than Revision 2, as referenced in GALL-SLR AMP XI.M12. Therefore, the staff needs to confirm that the use of the fracture toughness data in accordance with Revision 1 of NUREG/CR-4513 does not affect the crack stability determined in the LBB fracture mechanics analyses.

Request:

1. *Discuss the fracture toughness data of plant-specific (or representative) primary loop stainless steel welds to confirm that the fracture toughness data of the welds are greater than the fracture toughness estimated for the CASS elbows. Alternatively, identify relevant references (e.g., references to topical reports) for the weld fracture toughness data.*

2. *In addition, clarify how the limit load analysis determines the material properties of the welds (e.g., flow stresses). Alternatively, identify relevant references (e.g., references to topical reports) for the weld material properties considered in the limit load analysis.*

3. *Clarify whether the fracture toughness values of the CASS elbows estimated in accordance with Revision 2 of NUREG/CR-4513 are more limiting than the saturated fracture toughness (fully aged) in accordance with Revision 1 of NUREG/CR-4513 for the cold leg, crossover leg and hot leg locations. If not, please discuss whether the use of the fracture toughness value in accordance with NUREG/CR-4513, Revision 1 affects the conclusion of the crack stability analysis.*

Dominion Response:

Response to RAI 4.7.3-1 Request 1:

Based on historic testing done by Westinghouse on representative plants, WCAP-9787, "Tensile and Toughness Properties of Primary Piping Weld Metal for Use in Mechanistic Fracture Evaluation," and WCAP-9558, Revision 2, "Mechanistic Fracture Evaluation of Reactor Coolant Pipe Containing a Postulated Circumferential Through-Wall Crack," has shown that wrought and cast austenitic stainless steel (CASS) piping exhibits more limiting (unaged) fracture toughness properties than the weld metal. Since NUREG/CR-4513, Revision 2, "Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems," indicates that CASS material's aged lower bound fracture toughness values are similar to that of Submerged Arc Welds (SAWs), and since SAWs are considered to be the most limiting of welding processes (with respect to Gas Tungsten Arc Welds and Shielded Metal Arc Welds), it is concluded that the aged fracture toughness of the wrought and cast stainless steel base metal (including the CASS elbows) is more limiting than the aged fracture toughness of the weld metal.

Response to RAI 4.7.3-1 Request 2:

The limit load analyses consider material properties (yield and ultimate strength) of the base metal, but not the material properties of the weld metal, as the base metal (piping) is considered to have more limiting material properties than the weld metal. In addition to using the limiting yield and ultimate strength of the base metals, the limit load analyses at the critical locations consider a Z-factor penalty. The Z-factor is consistent with the methodology of SRP 3.6.3 (Federal Register/Vol. 52, No. 167/Friday August 28, 1987/Notices, pp. 32626-32633) and accounts for reduction of the material toughness due to the welding process used during construction. Combining the limiting yield and ultimate strength of the base metals with the Z-factor penalty of the weld, ensure the limit load analysis bounds both the weld metal and base metal.

Response to RAI 4.7.3-1 Request 3:

WCAP-15550, Revision 2, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Surry Units 1 and 2 Nuclear Power Plants for the Subsequent License Renewal Program (80 Years) Leak-Before-Break Evaluation," used NUREG/CR-4513, Revision 2, "Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems." (Reference Section 4.0, Material Characterization, in WCAP-15550, Revision 2, for documentation). The LBB evaluations in WCAP-15550, Revision 2, used NUREG/CR-4513, Revision 2, since it is the most recent version of NUREG/CR-4513 approved by the NRC in May 2016 prior to publication of both WCAP-15550, Revision 1, in June 2017 and WCAP-15550, Revision 2, in March 2019. WCAP-15550, Revision 0, published in August 2000 used NUREG/CR-4513, Revision 1, which was the latest approved version by the NRC at that time. Therefore, WCAP-15550, Revision 0, 1, and 2 all used lower bound saturated toughness approved by NRC from NUREG/CR-4513, Revision 1 and Revision 2, at the time of publication. It should be noted that for the LBB critical locations, the NUREG/CR-4513, Revision 2, fracture toughness values are generally more limiting or similar in magnitude to the values from NUREG/CR-4513, Revision 1. Overall, LBB analyses have acceptable margins when performing the elastic-plastic J-integral evaluations with the use of lower bound fracture toughness properties from NUREG/CR-4513, Revision 1 and Revision 2.

NUREG/CR-4513, Revision 2, revises the procedure and correlations used for predicting the change in fracture toughness properties of CASS components due to thermal aging, to account for the most current and larger fracture toughness database (than Revision 1) for CASS materials aged up to 100,000 hours at 290–350°C (554–

633°F). The methodology for estimating fracture properties has been extended to cover a wider range of CASS materials with a ferrite content of up to 40% in Revision 2. A more detailed discussion on the differences between NUREG/CR-4513, Revision 1 and Revision 2 is presented in the Executive Summary and Section 1, Introduction, of NUREG/CR-4513, Revision 2. Therefore, the fracture toughness correlations from Revision 2 are appropriate for use in the LBB evaluations. It should be noted that during the 2016-2017 period, both NUREG-2191 (GALL-SLR) and NUREG/CR-4513, Revision 2, were being drafted concurrently. Therefore, NUREG-2191, at that time, referenced the latest approved NUREG/CR-4513 version which was Revision 1. However, for LBB analysis purposes, it is appropriate to use the most recent NRC approved version which is Revision 2.

RAI 4.7.3-2

See Enclosures 2 and 3 for Proprietary and Non-proprietary responses, respectively.

RAI 4.7.3-3

See Enclosures 2 and 3 for Proprietary and Non-proprietary responses, respectively.

RAI 4.7.3-4

Background:

SLRA Section 4.7.3 addresses a TLAA on leak-before break (LBB) for the reactor coolant system (RCS) primary loop. Dominion (applicant) indicated the LBB analysis for 80 years of operation is documented in WCAP-15550, Revision 2. Section 8 addresses the fatigue crack growth analysis to confirm that the potential fatigue crack growth does not affect the integrity of the primary loop piping and the crack stability determined in the LBB analysis.

Table 8-1 of the WCAP report lists the transients and transient cycle numbers that are used in the fatigue crack growth analysis for 80 years of operation. In comparison, Table 4.3.1-1 of the SLRA describes the 80-year transient cycle projections for the metal fatigue TLAAs based on Surry UFSAR Table 4.1-8 and Section 18.4.2.

Issue:

In contrast with Table 4.3.1-1 of the SLRA, Table 8-1 of WCAP-15550, Revision 2 does not include the "Inadvertent auxiliary pressurizer spray" transient in the fatigue crack growth analysis for the LBB TLAA. Section 8.0 of the WCAP report does not clearly describe why the "Inadvertent auxiliary pressurizer spray" transient is omitted in the fatigue crack growth analysis.

Request:

Describe the basis for why the fatigue crack growth analysis does not include the "Inadvertent auxiliary pressurizer spray" transient that is included in SLRA Table 4.3.1-1.

Dominion Response:

The original leak before break analysis performed by Westinghouse for generic resolution of the A-2 (Asymmetric Blowdown Loads on Reactor Coolant System) used the most limiting generic transients. For initial license renewal, a plant specific LBB report, WCAP-15550, Revision 0, was issued that included a fatigue crack growth analysis as a defense in depth approach that is not required by Standard Review Plan 3.6.3 (Federal Register/Vol. 52, No. 167/Friday August 28, 1987/Notices, pp. 32626-32633). Nonetheless, the transients used in the plant specific LBB analysis for initial license renewal and subsequent license renewal are outlined in Table 8-3 for Revision 0, Revision 1, and Revision 2 of WCAP-15550.

The design of the main loop piping is in accordance with ANSI B1.1; it is based upon 7000 equivalent full temperature thermal cycles. The "Inadvertent auxiliary pressurizer spray" transient is not part of the design of the main loop piping. The "Inadvertent auxiliary pressurizer spray" transient does not contribute to fatigue crack growth of the main loop piping. Table 4.3.1-1 of the SLRA provides a list of transients applicable to the fatigue monitoring program. Table 4.3.1-1 illustrates that SPS Units 1 and 2 are not projected to exceed 40 years of design cycles for the Section III vessels or the 7000 equivalent full temperature thermal cycles specified in ANSI B31.1 for the piping over an 80 year life time.

RAI 4.7.3-5

Background:

SLRA Section 4.7.3 addresses a TLAA on leak-before break (LBB) for the reactor coolant system (RCS) primary loop. SLRA Section A3.7.3 provides the UFSAR supplement for the LBB TLAA.

<u>*Issue:*</u>

SLRA Section A3.7.3 states that the WCAP-15550 report demonstrated compliance with LBB technology for the reactor coolant system piping for the 80-year operation. The staff notes that the LBB TLAA applies only to the reactor coolant system (RCS) primary loop piping and does not apply to the branch lines connected to the primary loop (e.g., accumulator and safety injection branch lines). In addition, the staff notes that the reference to the WCAP-15550 report in the UFSAR supplement does not include a specific revision (i.e., Revision 2) that provides the 80-year LBB analysis.

<u>*Request:*</u>

1. *Clarify whether the LBB TLAA applies only to the RCS primary loop piping. If so, revise the statement discussed in the SLRA Section A3.7.3 to reflect the specific scope of the LBB TLAA (i.e., LBB is only applied to the primary loop piping, but not to primary loop branch lines).*

2. *Revise the UFSAR supplement to include the specific revision of the WCAP-15550 report that provides the 80-year LBB analysis.*

<u>Dominion Response:</u>

<u>Response to RAI 4.7.3-5, Request 1:</u>

At the time the SLRA was submitted to the NRC, the only LBB analysis completed for SPS Units 1 and 2 was for the main loop reactor coolant piping described in WCAP-15550, Revision 2, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Surry Units 1 and 2 Nuclear Power Plants for the Subsequent License Renewal Program (80 Years) Leak-Before-Break Evaluation." The only TLAA, as defined by 10 CFR 54.3(a) criteria, pertaining to LBB is for the main loop reactor coolant piping described in WCAP-15550, Revision 2.

<u>Response to RAI 4.7.3-5, Request 2:</u>

SLRA Section A3.7.3 is supplemented, as shown in Enclosure 5, to indicate Revision 2 as the revision of WCAP-15550 that provides the 80-year LBB analysis for SPS SLR.

<u>SLRA Revision:</u>

SLRA Section A3.7.3 is supplemented as shown in Enclosure 5 to indicate the change noted above.

RAI 4.7.3-6

Background:

SLRA Section 4.7.3 addresses a TLAA on leak-before break (LBB) for the reactor coolant system (RCS) primary loop. Dominion (applicant) indicated the LBB analysis for 80 years of operation is documented in WCAP-15550, Revision 2. Sections 7.2 and 7.3 of WCAP-15550, Revision 2 address the limit load analysis for critical locations 1, 3, 6 and 15. Section 7.3 and associated Figures 7-2 through 7-5 indicate that Z factors are applied to the load calculations for the stainless steel piping (location 1) and cast austenitic stainless steel (CASS) elbows (locations 3, 6 and 15). These locations are in the piping and elbow base materials, but not in the welds.

Issue:

WCAP-15550, Revision 2 does not clearly indicate whether Z factors are applied to the axial (including pressure) and moment loads. The staff also finds a need to clarify why the applied Z factors are sufficiently high to confirm the structural integrity of the thermally aged CASS elbows.

Request:

1. *Clarify whether Z factors are applied to both axial (including pressure) and moment loads. If not, provide the technical basis for why the Z factors are not applied to both axial (including pressure) and moment loads.*

2. *Clarify why the applied Z factors are sufficiently high to confirm the structural integrity of the thermally aged CASS elbows. As part of the response, clarify whether the other conservatisms associated with the method and results of the limit load analysis (in addition to the Z factors) are sufficient to confirm the structural integrity of the CASS elbows.*

Dominion Response:

Response to RAI 4.7.3-6, Request 1:

The LBB evaluation consist of evaluating two failure mechanisms for cast austenitic stainless steel (CASS) components as discussed in Section 7 of WCAP-15550, Revision 2, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Surry Units 1 and 2 Nuclear Power Plants for the Subsequent License Renewal Program (80 Years) Leak-Before-Break Evaluation."

The first failure mechanism evaluated is based on J-integral evaluation to assess the local crack stability. In the J-integral evaluation, J_{app} is calculated based on the faulted loads without any Z-factors to account for reduction in fracture toughness. This is because the calculation of J_{Ic}, as part of the J-integral evaluations, already considers reduction in fracture toughness due to thermal aging of the CF8M materials at normal operating temperature over extended operating periods. This reduction in fracture toughness is based on NUREG/CR-4513, Revision 2, "Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems," correlations which have determined lower bound fracture toughness, (see discussion in Section 4.3 of WCAP-15550, Revision 2.) The results from the NUREG/CR-4513 ANL Research Program also indicated that "the lower-bound fracture toughness of thermally aged cast stainless steel is similar to that of submerged arc welds (SAWs)". Therefore, no additional Z-factors are necessary because the reduction in fracture toughness is already captured with the consideration of end-of-life fracture toughness values from NUREG/CR-4513.

The second failure mechanism evaluated is based on plastic instability (limit load). In this evaluation, the flawed pipe is predicted to fail when the remaining net section reaches a stress level at which a plastic hinge is formed (see Section 7.2 of WCAP-15550, Revision 2.) In this global failure mechanism, Z-factors are included based on the weld types. The Z-factors are applied on the faulted loads at the critical locations and are provided in Section 7.3 of WCAP-15550. The Z-factors, used in the limit load global failure evaluation, are applied to both the axial load (including pressure) and the moment load. The limit load evaluations with the incorporation of Z-factors are equated to the material flow stress to determine the critical flaw sizes in the LBB evaluation. The incorporation of Z-factors for limit load, as performed in WCAP-15550, is consistent with SRP 3.6.3 (Federal Register/Vol. 52, No. 167/Friday August 28, 1987/Notices, pp. 32626-32633).

Response to RAI 4.7.3-6, Request 2:

The limit load analyses consider material properties (yield and ultimate strength) of the base metal but not the material properties of the weld metal. The base metal (piping) is considered to have more limiting material properties than the weld metal. In addition to using the limiting yield and ultimate strength of the base metals, the limit load analyses at the critical locations consider a Z-factor penalty. The Z-factor is consistent with the methodology of SRP 3.6.3 (Federal Register/Vol. 52, No. 167/Friday August 28, 1987/Notices, pp. 32626-32633) and accounts for reduction of the material toughness due to the welding process used during construction. By combining the limiting yield and ultimate strength of the base metals with the Z-factor penalty of the weld, Dominion Energy's analysis ensures that both the weld metal and base metal are bounded. Therefore, use of more limiting material properties, in combination with the Z-factor, ensures that the LBB analysis is conservative relative to the structural integrity of the CASS elbows.

SRP 3.6.3 does not explicitly discuss consideration of the thermal aging of CASS material. However, to account for the thermal aging effect, a separate fracture mechanics analysis is performed which calculates the applied J-integral due to the faulted loading conditions (using the more-limiting base metal tensile properties) and compares the calculated J_{app} value to the thermally aged fracture toughness allowables (J_{Ic}, J_{max}, T_{mat}) of the CASS material.

Therefore, the limit load analysis considers the reduced fracture toughness of the weld (Z-factor), and the J-applied analysis considers the reduced fracture toughness of the thermally aged CASS material per NUREG/CR-4513, Revision 2, "Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems."

RAI 4.7.6-1

Background:

The regulation in 10 CFR 54.21(c)(1)(i) states that, for a specific time limited aging analyses (TLAA) that is dispositioned in accordance with this regulation, the applicant must demonstrate that the analyses remain valid for the period of the SPEO. Subsequent license renewal application (SLRA) Section 4.7.6, "Reactor Coolant Pump Code Case N-481," identifies the examination of the reactor coolant pump (RCP) casing in the current licensing basis as a TLAA item.

Cast austenitic stainless-steel reactor coolant pump casings are susceptible to thermal aging. As an alternative to screening for significance of thermal aging, no further actions are needed if an applicant demonstrates that the original flaw tolerance evaluation performed as part of Code Case N-481 implementation remains bounding and applicable for the SPEO, or the evaluation is revised to be applicable to 80 years.

The license[e] stated that WCAP-13045, 'Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems' presents the fracture mechanics-based integrity evaluation that was performed to demonstrate compliance with ASME Code Case N-481. However, the technical basis for WCAP-13045 was based on an assumed 40-year life.

To demonstrate continued compliance during SPEO, the Pressurized Water Reactor Owner's Group (PWROG) re-evaluated WCAP-13045 associated with the application of Code Case N- 481 to the RCP casing during the SPEO. The licensee stated that that the fracture mechanics integrity assessment in PWROG-17033, "Update for Subsequent Licensee Renewal: WCAP- 13045, 'Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems'," as well as the requirements of Code Case N-481, were reaffirmed to demonstrate that visual inspection, in lieu of volumetric inspections, for pump casing remain valid for an 80-year life. The applicant referenced the topical report PWROG-17033, Revision 1 as being applicable to its SLRA.

By letter dated June 14, 2018, PWROG submitted, for NRC review and approval, topical report PWROG-17033-P & NP, Revision 1, under the NRC's topical report review process for generic use. The NRC staff is currently reviewing PWROG-17033, Revision 1 for generic use in SLRA's for PWR's that use Westinghouse designed RCP's[.]

Issue:

The crack stability analysis in WCAP-13045 and updated in PWROG-17033, Revision 1, relies on enveloping or bounding criteria. A licensee who references these topical reports must show that the plant-specific pump casings fall under the umbrella established by the analyses in these topical reports.

Request:

For the crack stability analysis, confirm that the screening loadings (forces, moments, J_{app} and T_{app}) used in WCAP-13045 bound the Surry Units 1 and 2 plant-specific loadings. Confirm the limiting material fracture toughness values (J_{Ic}, T_{mat}, and J_{max}) used in WCAP-13045 and PWROG-17033, Revision 1, bound the fracture toughness values of the plant-specific RCP casings at Surry Units 1 and 2. If the screen loadings and material fracture toughness values in the WCAP-13045 and PWROG-17033 reports bound plant-specific values, discuss how the analyses in the topical reports are bounding in the subsequent license renewal application for Surry Units 1 and 2. If the screen loadings or material fracture toughness values in the WCAP-13045 and PWROG-17033 reports do not bound plant-specific values, submit a Surry plant-specific crack stability analysis to demonstrate structural integrity of the plant-specific RCP casings at Surry Units 1 and 2.

Dominion Response:

Dominion, through interaction with Westinghouse Electric Company LLC, has confirmed that for the crack stability analysis, the screening loadings (forces and moments) used in WCAP-13045 bound the SPS Units 1 and 2 loadings, even when considering plant-specific system operational changes such as power uprates or plant modifications. In addition, the material fracture toughness values (J_{Ic}, T_{mat}, and J_{max}) reported in WCAP-13045 for CF8 material are more limiting than the SPS Units 1 and 2 fracture toughness values, and the J_{app} and T_{app} values used to demonstrate crack stability in the WCAP-13045 analysis for CF8 material are identical to the J_{app} and T_{app} values for SPS Units 1 and 2. As stated in PWROG-17033, the fracture toughness values reported in WCAP-13045 for CF8 material are at the fully aged saturated condition and are, therefore, applicable to 80 years of service life. As a result, the crack stability analysis performed in WCAP-13045 adequately demonstrates crack stability of the SPS Units 1 and 2 pump casings for 80 years.

RAI 4.7.6-2

Background:

The regulation in 10 CFR 54.21(c)(1)(i) states that, for a specific time limited aging analyses (TLAA) that is dispositioned in accordance with this regulation, the applicant must demonstrate that the analyses remain valid for the period of the SPEO. Subsequent license renewal application (SLRA) Section 4.7.6, "Reactor Coolant Pump Code Case N-481," identifies the examination of the reactor coolant pump (RCP) casing in the current licensing basis as a TLAA item.

Cast austenitic stainless-steel reactor coolant pump casings are susceptible to thermal aging. As an alternative to screening for significance of thermal aging, no further actions are needed if an applicant demonstrates that the original flaw tolerance evaluation performed as part of Code Case N-481 implementation remains bounding and applicable for the SPEO, or the evaluation is revised to be applicable to 80 years.

The license[e] stated that WCAP-13045, 'Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems' presents the fracture mechanics-based integrity evaluation that was performed to demonstrate compliance with ASME Code Case N-481. However, the technical basis for WCAP-13045 was based on an assumed 40-year life.

To demonstrate continued compliance during SPEO, the Pressurized Water Reactor Owner's Group (PWROG) re-evaluated WCAP-13045 associated with the application of Code Case N- 481 to the RCP casing during the SPEO. The licensee stated that that the fracture mechanics integrity assessment in PWROG-17033, "Update for Subsequent Licensee Renewal: WCAP-13045, 'Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems'," as well as the requirements of Code Case N-481, were reaffirmed to demonstrate that visual inspection, in lieu of volumetric inspections, for pump casing remain valid for an 80-year life. The applicant referenced the topical report PWROG-17033, Revision 1 as being applicable to its SLRA.

By letter dated June 14, 2018, PWROG submitted, for NRC review and approval, topical report PWROG-17033-P & NP, Revision 1, under the NRC's topical report review process for generic use. The NRC staff is currently reviewing PWROG-17033, Revision 1 for generic use in SLRA's for PWR's that use Westinghouse designed RCP's

Issue:

The fatigue crack growth (FCG) analysis in WCAP-13045 as updated in PWROG-17033, Revision 1, relies on enveloping or bounding criteria. A licensee who references these topical reports must show that the plant-specific pump casings fall under the umbrella established by the analyses in these topical reports.

Request:

For the FCG analysis, confirm that the transient cycles specified in the WCAP-13045 or PWROG-17033 report bound the plant-specific transient cycles for the 80 years of operation at Surry Units 1 and 2. Confirm that the screening loadings used in the FCG analysis in WCAP-13045 bound the plant-specific applied loadings, considering potential increase in applied loading caused by plant-specific system operational changes, power uprate or plant modifications. If the FCG analysis inputs in WCAP-13045 bound the plant-specific conditions at Surry Units 1 and 2, discuss how they are bounding in the subsequent license renewal application for Surry Units 1 and 2. If the FCG analysis inputs in WCAP-13045 do not bound the plant-specific conditions, provide a plant-specific analysis to demonstrate the FCG of the postulated flaw in the Surry RCP casings is within acceptable criteria as part of the subsequent license renewal application.

Dominion Response:

The transient set specified in WCAP-13045 and PWROG-17033, Revision 1 is generic. To ensure conservatism in the FCG results presented in PWROG-17033, Revision 1, the FCG cycles for 40 years, as identified in WCAP-13045, were doubled for 80 years. This accounts for potential differences between the generic transient set used for the FCG analysis and the actual transient set used in the plant-specific validation work for SPS subsequent license renewal (SLR). The projected number of cycles for 80 years of plant operation at SPS will not exceed the number of design cycles for 40 years. The SPS SLR transient set was reviewed against the generic transient set. The results for the generic FCG analysis from WCAP-13045 are identical to the FCG results for the plant-specific validation work for SPS SLR.

With regard to loadings, the screening loadings used in the FCG analysis in WCAP-13045 continue to bound the plant-specific loadings, even when considering plant-specific system operational changes such as power uprates or plant modifications.

In summary, the FCG cycles specified for 40 years in WCAP-13045 were doubled for 80 years in PWROG-17033, Revision 1 because the report is generic. For SPS SLR, the cycles for 80 years of plant operation are projected to remain within the 40 year number of design cycles. Any differences between the generic transient set and the SPS SLR transient set will have an insignificant effect on FCG (since the combination of transient cycles and transient severity postulated in WCAP-13045 bound the FCG analysis for SPS). The loads for SPS SLR are also within the screening values used in WCAP-13045. Thus, the FCG information in PWROG-17033, Revision 1 bounds the plant-specific FCG for the 80 years of operation at SPS Units 1 and 2.

RAI-B2.1.1-1

Background:

Surry SLRA AMP B2.1.1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program is an existing condition monitoring program that manages cracking, loss of fracture toughness, and loss of material. The program consists of periodic volumetric, surface, and/or visual examination and leakage tests of ASME Class 1, 2, and 3 pressure-retaining components, including welds, pump casings, valve bodies, integral attachments, and pressure retaining bolting for assessment, identification of signs of degradation, and establishment of corrective actions.

<u>*Issue:*</u>

Item 1 in the Operating Experience Summary section of Surry SLRA AMP B2.1.1, ASME Section XI Inservice Inspection IWB, IWC, and IWD, identifies an embedded indication detected in a Unit 2 reactor vessel inlet nozzle-to-shell weld region that has remained in service. The applicant stated that it performed a flaw evaluation to show that the indication is acceptable for continuing plant operation.

<u>*Request:*</u>

1. *Discuss whether the flaw evaluation was performed for a time period to the end of subsequent license renewal period (i.e., 80 years). If yes, discuss whether the final flaw/indication size at the end of 80 years is less than the allowable flaw size. If the flaw evaluation was not performed to the end of 80 years, provide justification.*

2. *Discuss whether this indication was analyzed as part of the Time Limited Aging Analysis. If not, provide justification.*

3. *The ASME Code, Section XI, IWB/C/D-2000 requires successive examinations for the flaws that remain in service and are dispositioned by a flaw evaluation. Discuss whether the three successive examinations have been performed on the Unit 2 reactor vessel inlet nozzle-to-shell weld region.*

<u>**Dominion Response:**</u>

<u>Response to RAI B2.1.1-1, Request 1:</u>

1. In 2005 an embedded flaw was discovered in Unit 2 weld RC-R-1.1 / 2-15 (reactor vessel inlet nozzle-to-shell weld region). A flaw evaluation was performed to justify returning the unit to service until the next scheduled inspection, which was anticipated to be in ten years. Subsequent to the flaw evaluation, a relief request (Virginia Electric and Power Company Letter 12-267 to the NRC dated April 25, 2012, "Surry Power Station Units 1 and 2, ASME Section XI Inservice Inspection (ISI) Program, Request for Alternative – Implementation of Extended Reactor Vessel Inservice Inspection Interval, Relief Request CMP-007 and CMP-009") was processed to support the alternate inspection interval of 20 years. A flaw evaluation has not been performed to Year 80. Weld RC-R-1.1 / 2-15 is currently scheduled to be examined during the next 10-year inservice inspection activity in spring 2023 (ISI Interval 5, Period 3), which is likely the last inspection prior to the Subsequent Period of Extended Operation (SPEO). Any flaw indication found during the 2023 inspection would require evaluation of the examination results consistent with Code

Case N-526, “Alternative Requirements for Successive Inspections of Class 1 and 2 Vessels.”

Response to RAI B2.1.1-1, Request 2:

The evaluation of the embedded flaw indication is not part of a Time Limited Aging Analysis since the flaw was dispositioned as acceptable per Code Case N-526, “Alternative Requirements for Successive Inspections of Class 1 and 2 Vessels”.

Response to RAI B2.1.1-1, Request 3:

Code Case N-526 had been implemented for SPS prior to 2005. The three conditions listed below for the applicability of Code Case N-526 were confirmed for the evaluation of the Unit 2 embedded flaw.

i. The flaw is characterized as subsurface in accordance with Figure 1 of Code Case N-526.
ii. The NDE technique and evaluation that detected the flaw with respect to both sizing and location shall be documented in the flaw evaluation report.
iii. The vessel containing the flaw is acceptable for continued service in accordance with IWB-3600, and the flaw is demonstrated acceptable for the intended service of this.

The use of Code Case N-526 provided an alternative to the ASME Section XI, Subsection IWB-2420(b) requirement to re-examine the vessel examination volume containing the subsurface flaw.

RAI- B2.1.1-4

Background:

Surry SLRA Section 3.1.2.2.2 discusses degradation of loss of material due to general, pitting and crevice corrosion and the associated aging management programs.

Issue:

In Surry SLRA Section 3.1.2.2.2, Dominion stated that the One-Time Inspection program, AMP B2.1.20, will use magnetic particle testing to inspect the continuous circumferential transition cone closure weld on each steam generator (minimum 25 percent examination coverage of each weld) prior to the subsequent period of extended operation.

Request:

Discuss whether the magnetic particle testing will achieve 100 percent or essentially 100 percent examination coverage of the circumferential transition cone closure weld on each steam generator. Discuss the technical basis for the minimum 25 percent examination coverage of each weld.

Dominion Response:

The SPS response to Information Notice 90-04, "Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators", included inspections required by ASME Section XI, and an additional inspection of a representative steam generator transition cone girth weld using magnetic particle testing (MT). The MT of the upper girth weld on the single steam generator achieved 100% coverage.

For subsequent license renewal, the periodic examinations of the steam generator transition cone girth welds will continue to be performed as described in the *ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD* program (B2.1.1).

Consistent with NUREG-2192, Section 3.1.2.2.2, a one-time inspection will be performed for the transition cone closure weld on each steam generator using MT as described in the *One-Time Inspection* program (B2.1.20). This one-time inspection will confirm the effectiveness of the *Water Chemistry* program (B2.1.2). For the transition cone closure weld on each steam generator, the one-time MT inspection is intended to cover essentially 100% of the total weld length.

SLRA Revisions:

SLRA Sections B2.1.20, *One Time Inspection* program, Program Description, Table A4.0-1, Item 20, and FER Item 3.1.2.2.2 are supplemented, as indicated in Enclosure 5, to indicate that the one-time MT inspection on each steam generator transitioin cone closure weld is intended to cover essentially 100% of the total weld length, as indicated above.

RAI B2.1.18-1

Background:

In its SLRA, Section B2.1.18, "Fuel Oil Chemistry," the applicant claimed consistency with the "Monitoring and Trending" program element of Section XI.M30 of the GALL-SLR as it relates to testing for water and sediment in fuel oil. In its SLRA, the applicant *stated that standard ASTM D1796-83, "Standard Test Method for Water and Sediment in Fuel Oil by the Centrifuge Method," is used in the Fuel Oil Chemistry program to test fuel oil for water and sediment.*

The GALL-SLR Report Section XI.M30, "Fuel Oil Chemistry," recommends that the AMP monitor parameters such as water and sediment in diesel fuel oil. Additionally, the GALL-SLR Report references standard ASTM D975, "Standard Specification for Diesel Fuel Oils," which provides guidance for determining the appropriate test methods to test for certain parameters, including water and sediment, in diesel fuel oil. This standard recommends the use of ASTM D2709, "Standard Test Method for Water and Sediment in Middle Distillate Fuels by Centrifuge," for measuring water and sediment in Grade 2-D diesel fuel oil (the same grade that the Surry Power Station (SPS) uses). The standard recommends use of ASTM D1796, "Standard Test Method for Water and Sediment in Fuel Oils by the Centrifuge Method (Laboratory Procedure)," to test for water and sediment in Grade 4-D diesel fuel oil, which has different physical and chemical properties (e.g. higher viscosity) than Grade 2-D diesel fuel oil.

Issue:

In its SLRA that applicant states that it uses ASTM D1796-83 to test for water and sediment in its diesel fuel oil. However, this standard is recommended for use for different grade fuel oils than what is used at SPS.

Request:

Explain why the use of ASTM D1796-83 to test for water and sediment in Grade 2-D diesel fuel oil is appropriate given that the standard is specified for grade 4-D fuel oil (as per ASTM D975) which has different physical and chemical properties than the fuel oil used at Surry.

Dominion Response:

The quarterly surveillance requirement to verify the fire pump storage tank parameters are within the limits specified in ASTM-D975-74, Table 1 for viscosity, water, and sediment.

The *Fuel Oil Chemistry* program is implemented using ASTM standards including D975-74 and ASTM D1796-83. Since inception of the *Fuel Oil Chemistry* program, the ASTM standards have evolved such that later versions of ASTM D1796 are now intended for higher viscosity fuel oils such as Grade No. 4-D, and lower viscosity fuel oils such as Grade No. 2-D are now tested for water and sediment using ASTM D-2709. The changes to the specified standards based on viscosity went into effect with the issuance of D975-95. The following Table shows how the standards have evolved since issuance of D975-74.

Comparison of ASTM Standard Specifications for Fuel Oil from 1974 to Present					
Standard Spec.	Centrifuge Std.	Grade Nos.	Preheat Temp. (°F)	Relative Centrifugal Force (rcf)	Water and Sediment % vol. (max.)
D975-74	D1796-83	2-D	120	500-800	0.05
		4-D	120	500-800	0.5
D975-95	D2709-96	2-D	70-90	800 (+/- 60)	0.05
	D1796-97	4-D	140	500-800	0.5
D975-13*	D2709-96 (R2011)*	2-D	70-90	800 (+/- 60)	0.5
	D1796-11*	4-D	140	500-800	0.05
D975-19	D2709-16	2-D	70-90	800 (+/- 60)	0.5
	D1796-11 (R2016)	4-D	140	500-800	0.05

*Referenced in NUREG-2191 XI.M30

ASTM D975-74, and later versions up to D975-94, specify that tests for water and sediment be performed to ASTM D1796 for Grade Nos. 1-D, 2-D, and 4-D. ASTM D975-95 and later versions specify ASTM D2709 for testing water and sediment for Grade Nos. 1-D and 2-D, and ASTM D1796 is now specified for the higher viscosity Grade No. 4-D fuel oil. A comparison of ASTM D1796-83 with ASTM D2709-96 shows that both tests are by centrifuge method, and the requirements for the test apparatus are essentially the same. Notable differences are the specified sample temperatures and the specified relative centrifugal force used. For ASTM D1796-83, the sample centrifuge tube is immersed in a 120°F bath for 10 minutes and spun to a relative centrifugal force (rcf) of 500 - 800 rcf, whereas ASTM D2709-96 specifies the sample to be 70°F to 90°F and spun to 800 rcf (+/- 60). ASTM D1796-11 (re-approved in 2016) was also reviewed. ASTM D1796-11 requires the same centrifugal force as D1796-83

(500-800 rcf), but requires the sample to be at a temperature of 140°F instead of 120°F. In summary, when testing for water and sediment by centrifuge, the later versions of ASTM D975 no longer require the lower viscosity Grade Nos. 1-D and 2-D fuel oils to be heated to the same temperature required for the higher viscosity Grade No. 4-D fuel oil.

The ability of a centrifuge separator to remove water and sediment is dependent on the fuel oil's density and viscosity. The difference in density between water and the sediments in the fuel oil and the fuel oil itself is the driving force for the centrifugal separation process. At standard conditions, the grades of fuel oil evaluated have a specific gravity of less than 1.0. Typical API gravity values at 60°F are 20 - 28°API (Specific Gravity 0.93 to 0.89) for Grade No. 4-D fuel oil, and 30 - 38°API (Specific Gravity 0.88 to 0.84) for Grade No. 2-D fuel oil. Specific gravity of fuel oil is reduced with increasing temperature. While increasing the temperature of water also slightly reduces the water density, the change in temperature has a larger effect on fuel oil density. In addition, raising the temperature of the sample reduces the fuel oil viscosity, which also facilitates the separation of water and sediment. The viscosity of Grade No. 4-D fuel oil is appreciably higher than the viscosity of Grade No. 2-D fuel oil at the same temperature. By preheating the fuel oil sample, since both viscosity and density are lowered, separation of water and sediment in a centrifuge is improved for all grades of fuel oil evaluated. Due to the differences in density and viscosity between the Grade No. 4-D fuel oil and the Grade No. 2-D fuel oil, it is reasonable to specify a higher preheat for centrifuging the Grade No. 4-D fuel oil. Although for the later ASTM standards it is no longer deemed necessary to test the Grade No. 2-D fuel oil at the higher preheat temperature, the use of the older standard with the higher preheat temperature does not invalidate the test results.

In conclusion, the use of ASTM D1796-83 for testing water and sediment for Grade No. 2-D fuel oil is acceptable for the purposes of the *Fuel Oil Chemistry* program, and the use of this standard and version is not considered to be an exception to NUREG-2191, XI.M30.

RAI B2.1.27-1

Background:

SLRA Section B2.1.27, "Buried and Underground Piping and Tanks," states the following:

1. *"[t]he buried carbon steel piping of the fuel oil system for emergency electrical power system is the only buried piping that is protected by an active cathodic protection system."*

2. *"[t]he balance of piping and tanks within the scope of subsequent license renewal are not provided with cathodic protection. Based on soil sampling and testing, it has been determined that installation and operation of cathodic protection is not necessary."*

3. *"[t]he Buried and Underground Piping and Tanks program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M41, Buried and Underground Piping and Tanks."*

GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," Table XI.M41-1, "Preventive Actions for Buried and Underground Piping and Tanks," recommends that cathodic protection is provided for buried steel and cementitious piping and tanks. In addition, the "preventive actions" program element of GALL-SLR Report AMP XI.M41 states the following:

1. *"[c]athodic protection is supplied for reinforced concrete pipe and prestressed concrete cylinder pipe. Applicants provide justification when cathodic protection is not provided."*

2. *"[f]ailure to provide cathodic protection in accordance with Table XI.M41-1 may be acceptable if justified in the SLRA. The justification addresses soil sample locations, soil sample results, the methodology and results of how the overall soil corrosivity was determined, pipe to soil potential measurements and other relevant parameters.*

3. *If cathodic protection is not provided for any reason, the applicant reviews the most recent 10 years of plant-specific operating experience (OE) to determine if degraded conditions that would not have met the acceptance criteria of this AMP have occurred. This search includes components that are not in-scope for license renewal if, when compared to in-scope piping, they are similar materials and coating systems and are buried in a similar soil environment. The results of this expanded plant-specific OE search are included in the SLRA."*

During the audit, the staff noted the following: (a) Preventive Action Category D has been selected for buried steel piping (i.e., external corrosion control is not required); (b) precast concrete water pipe will conform to American Water Works Association

(AWWA) C302, "Standard for Reinforced Concrete Pressure Pipe, Noncylinder Type;" and (c) plant-specific OE indicating instances of leaks, coating degradation, and minor external degradation of buried steel piping.

Issue:

An adequate basis was not provided for why cathodic protection is not necessary for the balance of piping and tanks within the scope of subsequent license renewal. For example:

1. *Consistent with GALL Report AMP XI.M41, specific details associated with how soil sampling and testing has demonstrated that installation and operation of cathodic protection is not necessary was not provided. For example, the technical basis for not providing cathodic protection does not address pipe-to-soil potential measurements and other relevant parameters (e.g., external corrosion rate measurements).*

2. *Instances of leaks and external degradation of buried steel piping were identified by the staff during the audit.*

The staff also noted that the specific type(s) of buried cementitious piping within the scope of subsequent license renewal may be relevant to the technical justification for not installing cathodic protection. During the audit, the staff reviewed a specification which noted that precast concrete water pipe will conform to AWWA C302. The staff seeks confirmation on whether this specification is applicable to all buried cementitious piping within the scope of subsequent license renewal.

Request:

1. *State the specific specification for buried cementitious piping within the scope of subsequent license renewal (e.g., AWWA C302).*

2. *State the basis for why the balance of buried steel and cementitious piping and tanks within the scope of subsequent license renewal are not provided with cathodic protection.*

Dominion Response:

Response to RAI B2.1.27-1, Request 1:

The buried cementitious piping within the scope of subsequent license renewal is precast reinforced concrete pipe installed with specifications that are consistent with AWWA C302, "Reinforced Concrete Pressure Pipe, Noncylinder Type." This pipe has two cages of reinforcement and is not prestressed.

Response to RAI B2.1.27-1, Request 2:

An Assessment of Additional Cathodic Protection and Site Soil Analysis at SPS was performed in 2012 and updated in 2018 to assess the need for additional cathodic protection at SPS. The assessment documented the following:

Soil Survey

Forty-four of 48 soil samples tested in 2012 were found to be mildly corrosive or non-corrosive (the corrosive samples were not applicable to buried components within the scope of license renewal). Additional soil survey results of 11 locations in 2018 confirmed that the 11 locations are non-corrosive. The soil was tested for soil resistivity, corrosion accelerating bacteria, pH, moisture, chlorides, sulfates, and redox potential. The highest AWWA C105, "Polyethylene Encasement for Ductile Iron Pipe Systems," rating occurred at one sample at the non-corrosive level. The only influencer according to the AWWA rating system was moisture content. Using the index of EPRI 3002005294, "Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants," the influencers were pH, oxygen reduction potential (ORP), resistivity, soil consortia, and moisture. In general the Indices provided equivalent results. The soil type and soil conditions from the analyzed soil samples at Surry in 2018 are mildly corrosive (lowest corrosive ranking) using the EPRI index and non-corrosive using the AWWA index.

Operating Experience (Components within the Scope of SLR)

In the performance of planned programmatic inspections, external corrosion has generally been found to be minimal. In cases where pipe wall thinning was identified, fitness for service calculations verified that minimum wall thicknesses were not challenged and provided additional monitoring considerations as required to track and trend the condition. The results of service calculations based on direct ultrasonic examination of piping without cathodic protection has consistently shown conservative corrosion rate estimates. Within the last 15 years, the following self-revealing issues were noted on piping within the scope of SLR:

- In 2004, a two-inch auxiliary feedwater line piping leak was identified due to poorly installed coating. As a corrective action, the Unit 1 and Unit 2 AFW recirculation system piping is no longer buried and was rerouted through the safeguards building basement.
- In 2012 a 10-inch condensate pipe leak due to cracking was repaired. The cracking was due to mechanical damage caused by excavating equipment.

Supplemental SLR Review of Surface Water Operating Experience

A supplemental review performed by NRC staff, that included piping not in the scope of SLR, did not identify age related failures of fire water piping during 10 years of surface water operating experience. Identified leakage was found to be attributed to packing/gasket leakage, valve stem damage, hydrant valve malfunction, and a valve out of position. Confirmation of the supplemental review will be documented in the Dominion response to the NRC Request for Confirmation of Information (RCI) [ADAMS Accession No. ML19163A154].

Program Enhancement for Pipe-to-Soil Potentials

Pipe-to-soil potential measurements were not addressed during the 2018 soil survey. As a result, the *Buried and Underground Piping and Tanks* program (B2.1.27) will be enhanced to obtain pipe-to-soil potential measurements for piping in the scope of SLR during the next soil survey within 10 years prior to entering the subsequent period of operation.

The mildly corrosive (lowest EPRI ranking) soil conditions, operating experience, and program enhancement to obtain pipe-to-soil potentials provide the basis for why the balance of buried steel and cementitious piping and tanks within the scope of subsequent license renewal are not provided with cathodic protection.

SLRA Revisions:

SLRA Section B2.1.27 and Table A4.0-1, Item 27 are supplemented, as shown in Enclosure 5, to indicate the change noted above.

RAI B2.1.27-2

Background:

SLRA Section B2.1.27 states "[d]epending on the material, preventive and mitigative techniques include external coatings." GALL-SLR Report Table XI.M41-1 recommends that the following are coated in accordance with the "preventive actions" program element of GALL-SLR Report AMP XI.M41: (a) buried steel, stainless steel, and cementitious components; and (b) underground steel and copper alloy components.

During the audit, the staff noted the following: (a) buried stainless steel piping in the containment spray, residual heat removal, chemical and volume control, and safety injection systems may be externally coated or wrapped; (b) buried stainless steel piping in the fuel oil system is not externally coated; (c) buried steel piping in the condensate, fuel oil, service water, chilled water, and ventilation systems may be coated with tar pitch with felt wrap, tape-wrap, or coal tar epoxy; (d) buried concrete piping does not have external coating; (e) underground steel and copper alloy components may be wrapped or coated; (f) original plant specifications required that buried plant piping be coated with a coal tar pitch/felt wrap system; and (g) buried fuel oil storage tanks are coated externally with "poxitar or approved equal."

Issue:

The staff seeks confirmation on whether the following are coated in accordance with the "preventive actions" program element of GALL-SLR Report AMP XI.M41: (a) buried steel, stainless steel, and cementitious piping and piping components; and (b) underground steel and copper alloy piping and piping components. In addition, an adequate basis for how the "poxitar or approved equal" external coating used on the buried fuel oil storage tanks is in accordance with the "preventive actions" program element of GALL-SLR Report AMP XI.M41 was not provided.

Request:

1. *Provide clarification regarding if the following are coated in accordance with the "preventive actions" program element of GALL-SLR Report Table XI.M41-1: (a) buried steel, stainless steel, and cementitious piping and piping components; and (b) underground steel and copper alloy piping and piping components. If all or portions of in-scope piping and piping components are not externally coated in accordance with the "preventive actions" program element of GALL SLR Report AMP XI.M41, provide justification for why external coatings are not provided.*

2. *State the basis for why the "poxitar or approved equal" external coating used on the buried fuel oil storage tanks is in accordance with the "preventive actions" program element of GALL SLR Report AMP XI.M41.*

Dominion Response:

Response to RAI B2.1.27-2, Request 1:

The buried and underground steel piping and piping components within the scope of subsequent license renewal (SLR) are encased in concrete or coated with coal tar enamel, coal tar epoxy, or polyolefin consistent with the "preventive actions" program element of NUREG-2191 XI.M41. The underground copper alloy piping and piping components within the scope of SLR are coated with tape wrap. The only buried uncoated stainless steel piping and piping components within the scope of SLR are two level instrumentation sensing lines for the emergency diesel generator fuel oil storage tanks. The remaining stainless steel piping and piping components within the scope of SLR are coated with coal tar epoxy or polyolefin in accordance with the "preventive actions" program element of NUREG-2191 XI.M41. The only buried cementitious piping and piping components without external coating within the scope of SLR are eight buried 96-inch concrete circulating water lines.

Uncoated Stainless Steel Segments

There are two uncoated buried segments of 0.375-inch diameter stainless steel lines have a total length of approximately 6.75 feet. This length represents 0.5% of the total of approximately 1415 feet of buried stainless steel piping within the scope of SLR. In 2014, an inspection of four nearby fuel oil lines found the soil quality to be satisfactory with good quality select backfill of slightly damp sand. In 2018, none of the soil samples analyzed had an EPRI 3002005294 stainless steel corrosion index rating greater than 9 (moderately corrosive) or an AWWA C 105 corrosion index rating greater than 2 (non-corrosive). These ratings were primarily due to ORP, sulfate reducing bacteria (SRB), and moisture.

Direct inspections of coated buried stainless steel piping within the scope of SLR and not within the scope of SLR, previously inspected in accordance with the Buried and Underground Piping and Tanks program (B2.1.27), indicated favorable aging management results with no loss of intended function due to aging. As an enhancement, an inspection of each uncoated buried stainless steel segment will be performed prior to the subsequent period of extended operation. After inspection, each uncoated stainless steel segment will be coated consistent with Table 1 of NACE

SP0169-2007, "Standard Recommended Practice, Cathodic Protection of Prestressed Concrete Cylinder Pipelines."

Uncoated Reinforced Concrete Segments

The eight concrete circulating water lines without external coating comprise the total of approximately 1000 feet of buried cementitious piping within the scope of SLR. The *Open Cycle Cooling Water Systems* program (B2.1.11) will periodically inspect for evidence of concrete aging in accessible internal surfaces of the concrete circulating water lines. The *Open Cycle Cooling Water Systems* program (B2.1.11) will require that evaluation of inspection results includes consideration of the acceptability of inaccessible buried surfaces when conditions exist in accessible surfaces that could indicate the presence of, or result in, degradation to inaccessible buried surfaces. One hundred percent of the accessible circulating water line internal surfaces will be inspected in a ten year period. The *Buried and Underground Piping and Tanks* program (B2.1.27) will opportunistically inspect buried concrete circulating water lines when scheduled maintenance work permits access. The justification for this approach is:

- One hundred percent of the accessible circulating water line internal surfaces will be inspected in a ten year period. Instead of one inspection of a 10 foot length for buried circulating water piping every 10 years.
- Ground water monitoring has shown historically the external environment of these circulating water lines to be non-aggressive. The internal environment is considered to be slightly more aggressive since the brackish water is drawn from the James River.
- The internal visual inspections require identification of cracking, corrosion of reinforcement, loss of material, or flow blockage. With exception of flow blockage, these aging effects are consistent with the aging effects that are managed for a buried environment.
- The *Structures Monitoring* program (B2.1.34) requires similar evaluations of reinforced concrete inspection results that include consideration of the acceptability of inaccessible buried surfaces when conditions exist in accessible surfaces that could indicate the presence of, or result in, degradation to inaccessible buried surfaces.

Operating experience of the internal concrete surfaces of the circulating water lines has been reviewed and there have been no conditions on the internal concrete surfaces that would impact the license renewal intended function.

- In November 2013, preventive maintenance inspection power washed the Unit 1D concrete circulating water piping. The as-left condition was satisfactory.
- In April 2015, inspection determined the Unit 1C concrete circulating water piping condition was satisfactory.
- In October 2015, the as-found condition of the Unit 2B concrete circulating water piping was satisfactory.
- In November 2016, the as-found condition of the Unit 1B concrete circulating water piping was satisfactory.
- In May 2017, inspection reported barnacles, hydroids, silt, and light fouling were observed in the Unit 2A concrete circulating water piping. The as-left condition was satisfactory.
- In May 2018, minimal biofouling was found in the Unit 1A concrete circulating water piping and the piping condition was reported to be satisfactory.
- In October 2018, minor silt and mud was found in the Unit 2C concrete circulating water piping, and the inspection results were satisfactory.
- In November 2018, the Unit 2D concrete circulating water piping was reported to be satisfactory.

As such, the external surfaces are considered to be acceptable based on the internal conditions of the concrete piping being used as a leading indicator. Aging management inspections of the buried uncoated concrete and stainless steel piping will provide reasonable assurance that the license renewal intended function will be maintained during the subsequent period of extended operation.

<u>Response to RAI B2.1.27-2, Request 2:</u>

NACE SP0169-2007 Table 1 accepts coal tar as a generic external coating system. The Poxitar product data sheet, identifies Poxitar as a coal tar based epoxy coating.

<u>SLRA Revisions:</u>

SLRA Sections B2.1.11 and B2.1.27, Table A4.0-1, Items 11 and 27, Table 3.3.2-5 and Table 3.3.1 Item 103 are supplemented, as shown in Enclosure 5, based on the above.

RAI B2.1.27-3

Background:

SLRA Section A1.16, "Fire Water System," states "[t]his program manages aging effects by conducting periodic visual inspections, flow testing, and flushes consistent with provisions of the 2011 Edition of National Fire Protection Association (NFPA) 25, "Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems.""

GALL-SLR AMP XI.M41 states for fire mains installed in accordance with NFPA 24, "Standard for the Installation of Private Fire Service Mains and Their Appurtenances," preventive actions beyond those in NFPA 24 need not be provided if the system undergoes a periodic flow test in accordance with NFPA 25. The staff notes that NFPA 24 provides provisions for external coatings in Section 10.8.3.5, "Corrosion Resistance," and backfill quality in Section 10.9, "Backfilling."

During the audit the staff noted the following: (a) buried fire protection piping has an external bituminous coating; and (b) the fire protection system was designed in accordance with applicable NFPA standards.

Issue:

During the audit, the staff noted that the fire protection system was designed in accordance with applicable NFPA standards; however, this observation does not specifically address if the fire protection system was designed in accordance with NFPA 24. The staff notes that an external bituminous coating meets the intent of NFPA 24, Section 10.8.3.5; however, based on the documents reviewed during the audit, the staff was not able to confirm that the backfill quality for buried fire protection piping meets the intent of NFPA 24, Section 10.9.

Request:

1. *State if all buried fire protection piping is externally coated with a bituminous coating. If buried fire protection piping is not externally coated with a bituminous coating, state the basis for how external coatings meet the intent of NFPA 24, Section 10.8.3.5.*

2. *State the basis for how backfill quality for buried fire protection piping meets the intent of NFPA 24, Section 10.9.*

Dominion Response:

Response to RAI B2.1.27-3, Request 1:

1. Surry specifications require buried cast iron fire protection piping to be coated with bituminous coating.

Response to RAI B2.1.27-3, Request 2:

2. Surry specifications require initial backfill material shall be selected material, free from cinders, ashes, refuse, vegetable or organic material [NFPA 24, 10.9.2], frozen material [NFPA 24, 10.9.4], boulders, rocks or stones [NFPA 24, 10.9.3]. Initial backfilling and tamping shall be done in layers taking care to avoid pipe and conduit displacement or damage [NFPA 24, 10.9.1].

In the Fire Protection Systems Review, the Fire Protection Water Supply Systems Outside loop references NFPA 24 and indicates the design is to be in accordance with Nuclear Energy Property Insurance Association recommendations and applicable NFPA standards.

RAI B2.1.27-4

Background:

SLRA Section B2.1.27 states the following:

> *Soil sampling and testing is performed during each excavation and a station-wide soil survey is also performed once in each 10-year period to confirm that the soil environment of components within the scope of license renewal is not corrosive for the installed material types. Soil sampling and testing is consistent with EPRI Report 3002005294, "Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants."*

Buried metallic materials within the scope of the Buried and Underground Piping and Tanks program include steel, gray cast iron, and stainless steel. NUREG-2191 XI.M41 states that soil has been determined to not be corrosive for the material type (e.g., AWWA C105, "Polyethylene Encasement for Ductile-Iron Pipe Systems," Table A.1, "Soil-Test Evaluation") is a factor in determining if Preventive Action Category E or F is appropriate for steel, which is inclusive of gray cast iron. GALL-SLR Report AMP

XI.M41 does not explicitly use soil corrosivity to guide inspection quantities for stainless steel.

During the audit the staff noted Preventive Action Category D has been selected for buried steel piping.

During its review of EPRI Report 3002005294, the staff noted that there are two tables that provide guidance related to determining soil corrosivity. Observations from the two tables are noted below.

- *Table 9-3, "ANSI/AWWA C105/A21.5 Soil Corrosivity Index for Ductile Iron in Soil," provides identical guidance to AWWA C105, Table A.1, regarding indexing pH, redox potential, sulfides, and moisture. Table 9-3 provides different guidance to AWWA C105, Table A.1 regarding indexing soil resistivity.*

- *Table 9-4, "Soil Corrosivity Index from BPWORKS," provides specific guidance for cast iron (column three), carbon steel (column four), and stainless steel (column seven). Parameters used to determine soil corrosivity are soil resistivity, pH, redox potential, sulfides, chlorides, soil moisture, and soil bacteria. Based on these parameters, soil can be classified as mildly corrosive, moderately corrosive, appreciably corrosive, or severely corrosive.*

Issue:

The SLRA did not state staff how EPRI Report 3002005294 will be utilized with respect to the Buried and Underground Piping and Tanks program. Specifically, the staff noted the following:

- *GALL-SLR Report AMP XI.M41 uses soil corrosivity as a factor in determining if Preventive Action Category E or F is applicable for buried steel piping; however, the staff noted during the audit that Preventive Action Category D has been selected for buried steel piping.*

- *EPRI Report 3002005294 provides two tables that provide guidance related to determining soil corrosivity. The SLRA did not state which one of these tables is used to determine soil corrosivity.*

    - *If EPRI Report 3002005294, Table 9-4 will be utilized (i.e., using column three for gray cast iron, column four for steel, and column seven for stainless steel), the SLRA did not state how "non-corrosive soil" determination was concluded* *because based on EPRI Report 3002005294, soil can only be classified as mildly corrosive, moderately corrosive, appreciably corrosive, or severely corrosive (i.e., there is no classification designated as "non-corrosive").*

- *GALL-SLR Report AMP XI.M41 does not explicitly use soil corrosivity to guide inspection quantities for stainless steel. A basis was not provided for how EPRI Report 3002005294 will be used to guide inspection quantities for stainless steel.*

- *SLRA Section B2.1.27 states that soil sampling and testing is performed to confirm that the soil environment of components within the scope of license renewal is not corrosive for the installed material types. The SLRA did not state what action(s) will be taken if soil is determined to be corrosive.*

<u>Request:</u>

Provide additional clarification regarding how EPRI Report 3002005294 will be utilized with respect to the Buried and Underground Piping and Tanks program. Specifically, address the following: (a) how "not corrosive" soil will be determined for each buried metallic material (i.e., steel, gray cast iron, and stainless steel) within the scope of subsequent license renewal; and (b) how the determination of "corrosive" versus "not corrosive" soil for each buried metallic material within the scope of subsequent license renewal impacts the Buried and Underground Piping and Tanks program (e.g., extent of inspections).

<u>Dominion Response:</u>

<u>Response to RAI B2.1.27-4(a):</u>

In 2018, soil surveys of 11 locations at SPS were performed. The placement of each boring sample location was determined such that soil samples could be collected a few feet laterally of in-scope target piping, within the pipe backfill material, and at a target depth equal to the centerline depth of the piping. Sampling, field measurements and sample analysis was conducted in accordance with industry guidance noted in EPRI Technical Report 3002005294, "Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants."

Soil corrosivity evaluations and ranking were performed consistent with soil survey indices in EPRI 3002005294 (Table 9-4, carbon steel and stainless steel columns) and AWWA-C105, "*Polyethylene Encasement for Ductile-Iron Pipe Systems.*" Exhibit 2 (at the end of this RAI response) indicates the EPRI carbon steel and stainless steel corrosivity indices for each of the values assigned to the soil characteristics. Exhibit 3 (at the end of this RAI response) indicates the AWWA corrosivity indices for each of the values assigned to the soil characteristics. The EPRI and AWWA indices are based upon a points system for the analysis results of the soil characteristic parameters. The 11 soil samples were analyzed for the following soil characteristics:

Soil Characteristics Analyzed
Resistivity (Ω cm)
pH
Redox potential (mV)
Sulfides
Moisture
Soil Consortia (Bacteria) [EPRI 3001005294 only]

AWWA-C105 Soil Corrosivity Index

AWWA Corrosivity Index	Corrosivity
0 – 9	Non-Corrosive
Greater than or equal to 10	Corrosive to Ductile Iron Pipe

EPRI 3002005294 Soil Corrosivity Index

EPRI Corrosivity Index	Corrosivity
0-5	Mildly Corrosive
5-10	Moderately Corrosive
10-15	Appreciably Corrosive
15+	Severely Corrosive

<u>2018 Soil Sample Corrosivity Index Comparison</u>

The soil survey results for each of the analyzed soil characteristics and the sample locations are documented in a SPS Engineering Report. A comparison of the EPRI and AWWA soil corrosivity index for each of the 11 soil samples is provided in Exhibit 1.

Exhibit 1
2018 Soil Samples: Comparison of EPRI and AWWA Corrosivity Index

Sample Location	EPRI Carbon Steel Corrosivity	EPRI Stainless Steel Corrosivity (Note 1)	AWWA
1	5	N/A	0
2 (Note 2)	5	N/A	0
3	5	N/A	1
4	4	N/A	0
5 (Note 3)	8	N/A	1
6	4	8	0
7	5	9	1
8	5	N/A	0
9	5	9	1
10	4	8	0
11 (Note 2)	9	N/A	2

Notes:
1. Stainless Steels (SS) include 604 SS, 316 SS, Martensitic SS, Duplex 2205, Duplex 2507, Super SS
2. Buried components at this sample location are not within the scope of SLR
3. Buried components at this sample location include buried fire protection piping within the scope of SLR that is managed by monitoring the activity of the jockey pump

With exception of carbon steel sample location 5, the sample locations associated with the buried components and within the scope of SLR had an EPRI carbon steel corrosivity index of 5 or less, which is categorized as mildly corrosive by EPRI 3002005294. There were no soil samples analyzed that had an EPRI carbon steel corrosivity index greater than 9. Sample locations 11 and 5 had the highest ratings, which was primarily due to higher moisture content, low pH and positive sulfate reducing bacteria (SRB). The only soil samples that are associated with stainless steel are sample locations 6, 7, 9 and 10. Of these sample locations, there were no soil samples analyzed that had an EPRI stainless steel rating greater than 9. These results were evaluated and concluded to be primarily due to oxygen reduction potential (ORP), SRB and moisture.

None of the soil samples had an AWWA index greater than 2 and thereby, are considered non-corrosive.

The EPRI and AWWA indices ranked the soil survey results in their lowest ranking. The carbon steel and stainless steel rankings confirms the soil environment for buried components within the scope of SLR is non-aggressive and the aging effects will be managed consistent with the *Buried and Underground Piping and Tanks* program

(B2.1.27) to provide reasonable assurance that the intended functions will continue to be maintained during the subsequent period of operation.

Response to RAI B2.1.27-4(b):

As discussed above, low soil corrosivity potential results have been demonstrated. The rankings confirm the soil environment for buried components within the scope of SLR is non-aggressive and aging effects are not expected to occur or are expected to progress very slowly. Additional soil environment considerations associated with the soil consortia characteristic of the EPRI Corrosivity Index also demonstrates a low soil corrosivity potential that is discussed below.

The sample population would be considered mildly corrosive for buried components within the scope of SLR based on resistivity values alone. Positive Oxygen Reduction Potential (ORP) conditions, above 100mV, indicate high oxygen concentrations (aerobic) in soil that do not promote reduction of sulfates to sulfides, which can lead to corrosive soil conditions. At SPS, the eleven samples analyzed were below the detectable levels for sulfides. Generally, pH levels greater than approximately 6.5 are considered less corrosive. Each of the soil samples with the exception of samples 11 and 5 had pH levels ranging from 7.36 to 8.99. Sample locations 11 (not within the scope of SLR) and 5 had the lowest pH at 5.24 and 5.76, respectively. The characteristics of sample locations 11 and 5 suggest that the soil sources may be from river sediments or dredge spoils associated with surface waters, which would have lower pH relative to soil pore water not associated with surface water bodies.

Each of the soil samples collected had ORP values greater than 300mV. These results indicate aerobic, oxygen rich soil conditions that do not promote the growth of sulfate reducing bacteria (SRB) that could lead to high levels of sulfide. SRB was detected within the eleven tested samples. However, the presence of SRB does not necessarily reflect corrosive conditions but that corrosive conditions could develop under certain soil conditions, which did not exist at the time of the 2018 soil survey. The high ORP and basic pH measured in each positive sample indicates aerobic soil conditions with high pH that do not promote the growth of SRB. The absence of detectable sulfide in the positive samples is further evidence that SRB is not active in site soil at the investigated locations.

RAI B2.1.27-5

Background:

GALL-SLR AMP XI.M41 states the following:

> *For coated piping or tanks, there is either no evidence of coating degradation, or the type and extent of coating degradation is evaluated as insignificant by an individual: (a) possessing a NACE Coating Inspector Program Level 2 or 3 inspector qualification; (b) who has completed the Electric Power Research Institute Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course; or (c) a coatings specialist qualified in accordance with an ASTM standard endorsed in Regulatory Guide 1.54, Revision 2, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants."*

During the audit, the staff noted that an individual with EPRI Comprehensive Coating Training or NACE Nuclear Power Plant Coating Training will evaluate whether the observed coating condition is acceptable.

Issue:

The SLRA lacked specificity on how the qualifications of the individual determining if the type and extent of coating degradation is insignificant will be consistent with the intent of GALL-SLR AMP XI.M41.

Request:

State the basis for how the qualifications of the individual determining if the type and extent of coating degradation is insignificant will be consistent with the intent of GALL-SLR AMP XI.M41.

Dominion Response:

Surry procedures require a coatings specialist to be qualified in accordance with ASTM D7108, Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist, which is endorsed in Regulatory Guide 1.54, Revision 2. Coating degradation indications such as peeling, delamination, blisters, cracking, flaking, and rusting will be evaluated by a qualified coatings specialist. Acceptance criteria and associated corrective actions will be consistent with the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28).

RAI B2.1.27-6

Background:

As amended by letter dated April 2, 2019, SLRA Section B2.1.27, Enhancement No. 3, states the following in part:

- *Procedures will be revised to specify that cathodic protection surveys use the -850mV polarized potential, instant off criterion specified in NACE SP0169-2007 for steel piping acceptance criteria unless a suitable alternative polarization criteria can be demonstrated. Alternatives will include the -100 mV polarization criteria, -750mV criterion (soil resistivity is less than 100,000 ohm-cm), -650mV criterion (soil resistivity is greater than 100,000 ohm-cm), or verification of less than 1 mpy [mils per year] loss of material rate. Alternatives will be demonstrated to be effective through verification of soil resistivity every five years, use of buried coupons, electrical resistance probes, or placement of reference cells in the immediate vicinity of the piping being measured. As an alternative to verifying the effectiveness of the cathodic protection system every five years, soil resistivity testing is conducted annually during a period of time when the soil resistivity would be expected to be at its lowest value (e.g., maximum rainfall periods).*

- *When using electrical resistance corrosion rate probes, the impact of significant site features and local soil conditions will be factored into placement of the probes and use of the data.*

GALL-SLR Report AMP XI.M41 recommends that the effectiveness of the cathodic protection system (i.e., verifying less than 1 mpy external loss of material rate) is verified (a) every year when using the 1 mpy criterion; and (b) every 2 years when using the 100 mV minimum polarization criterion. In addition, GALL-SLR Report AMP XI.M41 states when electrical resistance corrosion rate probes will be used, the application identifies how the impact of significant site features and local soil conditions will be factored into placement of the probes and use of probe data.

Issue:

1. *GALL-SLR Report AMP XI.M41 recommends that the effectiveness of the cathodic protection system is verified every year when using the 1 mpy criterion and every 2 years when using the 100 mV minimum polarization criterion. The statement in the enhancement that "[a]s an alternative to verifying the effectiveness of the cathodic protection system every five years..." implies that all alternatives to the -850 mV*

polarized potential, instant off criterion will have the effectiveness of the cathodic protection system verified every five years.

2. *The SLRA lacked specificity on how the impact of significant site features and local soil conditions will be factored into placement of the probes and use of probe data.*

Request:

1. *State the basis for why the effectiveness of the cathodic protection will be verified every five years when utilizing the 1 mpy and 100 mV minimum polarization cathodic protection acceptance criteria.*

2. *Provide clarification regarding how the impact of significant site features and local soil conditions will be factored into placement of the probes and use of probe data.*

References:

- *AWWA C105, "Polyethylene Encasement for Ductile-Iron Pipe Systems." Denver, Colorado: American Water Works Association. 2010.*

- *AWWA C302, "Reinforced Concrete Pressure Pipe, Noncylinder Type." Denver, Colorado: American Water Works Association. 2011.*

- *EPRI Report 3002005294, "Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants." Palo Alto, California: Electric Power Research Institute. November 06, 2015.*

- *NFPA 24, "Standard for the Installation of Private Fire Service Mains and their Appurtenances." Quincy, Massachusetts: National Fire Protection Association. 2010.*

- *NFPA 25, "Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems, 2011 Edition." Quincy, Massachusetts: National Fire Protection Association. 2011.*

Dominion Response:

Response to RAI B2.1.27-6, Request 1:

Consistent with NUREG-2191, the *Buried and Underground Piping and Tanks* program (B2.1.27) Acceptance Criteria (Element 6) Enhancement will be clarified, as shown in Enclosure 5, to indicate the following:

The external loss of material rate is verified:

- Every year the effectiveness of the cathodic protection system is verified by measuring the loss of material rate.
- Every two years when using the 100 mV minimum polarization
- Every 5 years when using the -750 mV or -650 mV criteria associated with higher resistivity soils. The soil resistivity is verified every 5 years.

Response to RAI B2.1. 27-6, Request 2:

In addition to a use of an individual qualified to NACE CP4, "Cathodic Protection Specialist," to determine the installation locations of the probes and the methods of use, the following will also be factored into the placement of soil corrosion probes if required:

- Consideration of soil data from the most recent soil survey (e.g. moisture content, pH, and resistivity measurements). For example, if the soil in the vicinity of the soil corrosion probe were less corrosive than at other piping locations, the soil corrosion probe could under-predict the corrosion rate at other point of interest along the pipe length.
- Consideration of adjacent or neighboring components or systems that might interfere with accurate probe readings. These include proximity of structures or components that might shield the current or act as large current collectors. These features could result in less protection provided to cathodically protected components.
- Probes should be installed close to the piping locations of interest which will result in more accurate corrosion rate data. NACE International Publication 05107, Appendix B recommends that the probe be installed 10 inches from the pipe.

SLRA Revisions:

SLRA Section B2.1.27 and Table A4.0-1, Item 27 are supplemented, as shown in Enclosure 5, based on the above.

RAI B2.1.28-1

Background:

SLRA Section B2.1.28, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," states "[t]he Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks."

GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," states the scope of the program includes components exposed to closed-cycle cooling water, raw water, treated water, treated borated water, waste water, fuel oil, and lubricating oil. The scope of the program does not include environments with elevated temperatures.

SLRA Table 3.1.2-3, "Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation," states that loss of coating integrity will be managed for the internally coated carbon steel pressurizer relief tank by the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program.

Updated Final Safety Analysis Report (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. In addition, UFSAR Section 4.2.2.5, "Pressurizer Relief Tank," states the following:

> *Steam discharged from the power-operated relief valves or from the safety valves passes to the pressurizer relief tank, which is partially filled with water at or near containment ambient temperature, under a predominantly nitrogen atmosphere. Steam is discharged under the water level to condense and cool by mixing with the water. The tank is equipped with a spray, and a drain to the vent and drain system (Section 9.7), which is operated to cool the tank following a discharge.*

Issue:

The SLRA or UFSAR does not contain information in regard to what the internal coatings are constructed of and the maximum temperature rating of the coatings. In addition, the SLRA or UFSAR does not include a description of the operational controls that would limit the time that the coatings would be exposed to an elevated temperature.

Request:

a) *State the coating material type and if possible manufacturer, and the coatings maximum design rating.*
b) *Describe any operational controls that would minimize the exposure time to higher temperatures.*

Dominion Response:

Response to RAI B2.1.28-1(a):

The pressurizer relief tank (PRT) internal coating is Amercoat 55, which is an epoxy based coating. The PRT coating is designed for temperature limits of 180°F Immersed and 250°F Atmospheric.

Response to RAI B2.1.28-1(b):

The annunciator response procedure for the PRT indicates that an alarm actuates when the PRT temperature is greater than or equal to 125°F. The plant operating procedure for the PRT requires the operator to return the PRT temperature to the normal temperature. The normal temperature band is 70 to 120°F. The tank has an internal spray and drain, which are designed to keep the PRT cool following the design discharge. The total spray flow rate of 150 gpm is designed to cool the PRT from 200°F to 120°F in one hour following the design discharge.

RAI B2.1.28-3

Background:

As amended by letter dated April 2, 2019, the "program description" section, Exception No. 2, and Enhancement No. 1 of SLRA Section B2.1.28 state that for piping, all accessible surfaces are inspected.

GALL-SLR Report AMP XI.M42 states for piping, either inspect a representative sample of seventy-three 1-foot axial length circumferential segments of piping or 50 percent of the total length of each coating/lining material and environment combination, whichever is less at each unit.

Issue:

The SLRA lacked specificity on how much inaccessible piping will not be inspected for each coating/lining material and environment combination (i.e., population). The staff seeks confirmation on whether the minimum inspection sample size for piping will be consistent with GALL-SLR Report AMP XI.M42 recommendations.

Request:

Provide clarification regarding how much inaccessible piping will not be inspected for each population. Provide justification if based on the amount of inaccessible piping, minimum inspection sample size for any population will not be consistent with GALL-SLR Report AMP XI.M42 recommendations.

Dominion Response:

The *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) inspects 100% of all accessible in-scope piping coated surfaces. The amount of inaccessible piping would be minimal and would not minimize NUREG-2191 representative sample requirements of seventy-three 1-foot axial circumferential segments of piping or 50% of the total length of each coating/lining material and environment combination, as recommended by NUREG-2191 XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks."

Condensate Polishing System Piping:
Additional inspections within the scope of subsequent license renewal will include a 3-inch condensate polishing line approximately 39 feet in length and a 3-inch condensate polishing line approximately 10 feet in length in the turbine building. Bolted connections facilitate piping disassembly for coating inspections. The piping is sectioned in lengths from six feet to 10 feet. The piping is flanged and bolted at both ends of each section and can be isolated and removed to inspect the internal coating. There are two elbows in each line that can also be removed to allow inspection. Borescopes or other inspection aids will be used to perform the inspection.

Water Treatment System Piping:
Additional inspections within the scope of subsequent license renewal will include a 1.5-inch line approximately two feet in length and a 4-inch line approximately 10 feet in length connected to a relief valve on top of the Unit 2 flash evaporator demineralizer tank in the turbine building. Bolted connections facilitate piping disassembly for coating inspections. The piping is flanged and bolted at each section and can be isolated and removed to allow inspection if necessary. Borescopes or other inspection aids will be used to perform the inspection.

Circulating Water and Service Water System Piping (AMP Exception 1):
For each unit, existing piping inspections are performed on 25% of the circulating water system (large bore piping) and service water system internal coatings every eighteen months, thereby inspecting 100% of the circulating water system and service water system piping every six years.

Corrosion-resistant Carbon Fiber Reinforced Polymer (CFRP) liner will be installed in the 96-inch circulating water inlet piping, and 24-, 30-, 36-, 42-, and 48-inch service water supply from the circulating water system to the recirculation spray heat exchangers and supply to the component cooling water heat exchangers. Based upon accessibility experienced during existing maintenance practices and recent installation operating experience, inaccessible CFRP lined piping is expected to be minimal.

Concrete Lined Piping (AMP Exception 3):
Concrete lined cast iron fire protection system main loop piping is buried. Exception 3 to the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) manages the effects of aging for the fire protection system main loop piping as described in NUREG-2191 XI.M27, "Fire Water System."

RAI B2.1.28-4

Background:

As amended by letter dated April 2, 2019, SLRA Section B2.1.28, Exception No. 2, states "[a]n exception is taken to performance of baseline inspections during each inspection interval."

SLRA Table A4.0-1, "Subsequent License Renewal Commitments," Item 28, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks *program," states "[i]nspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation."*

GALL-SLR Report AMP XI.M42 states the following:

> *If a baseline has not been previously established, baseline coating/lining inspections occur in the 10-year period prior to the subsequent period of extended operation. Subsequent inspections are based on an evaluation of the effect of a coating/lining failure on the in-scope component's intended function, potential problems identified during prior inspections, and known service life history. Subsequent inspection intervals are established by a coating specialist qualified in accordance with an ASTM International standard endorsed in Regulatory Guide (RG) 1.54. However, inspection intervals should not exceed those in Table XI.M42-1, "Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers."*

Issue:

For internally coated piping, piping components, heat exchangers, and tanks not covered by Exception Nos. 1 and 3, the staff seeks confirmation regarding if baseline inspections, qualifications of the individuals establishing subsequent inspections intervals, and maximum inspection interval length will be consistent with GALL-SLR Report AMP XI.M42. Specifically, the staff notes the following:

a) The revised SLRA Section B2.1.28 states that baseline inspections will not occur in each interval; however, SLRA Table A4.0-1 states that baseline inspection may occur prior to the subsequent period of operation (SPEO). The staff seeks confirmation regarding if and when baseline inspections will occur.

b) The revised SLRA Section B2.1.28 does not include a statement that subsequent inspection intervals are established by a coating specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54.

c) The revised SLRA Section B2.1.28 does not include a statement that inspection intervals will not exceed those specified in GALL-SLR Report Table XI.M42-1.

Request:

For internally coated piping, piping components, heat exchangers, and tanks not covered by Exception Nos. 1 and 3, clarify if: (a) baseline inspections will be performed consistent with GALL-SLR Report AMP XI.M42; (b) subsequent inspection intervals will be established by a coating specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54; and (c) inspection intervals will not exceed those specified in GALL-SLR Report Table XI.M42-1. Provide technical justification if (a), (b), or (c) will not be consistent with GALL-SLR Report AMP XI.M42 recommendations.

Dominion Response:

Response to RAI B2.1.28-4(a):

SLRA Section B2.1.28, *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program and Table A4.0-1, Item 28 will be supplemented, as shown in Enclosure 5, to indicate the following:

- If a baseline inspection has not been previously established, baseline coating/lining inspections will occur in the 10-year period prior to the subsequent period of extended operation. Subsequent inspection intervals are established by a coating specialist qualified in accordance with ASTM International Standards endorsed in RG 1.54, Revision 2, "Service Level I, II and III Protective Coatings Applied to Nuclear Power Plants."
- Inspection intervals will not exceed those specified in NUREG-2191, Table XI.M42-1, "Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers."

Response to RAI B2.1.28-4(b):

As indicated in the response to request (a) above, subsequent inspection intervals are established by a coating specialist qualified in accordance with ASTM International Standards endorsed in RG 1.54, Revision 2, "Service Level I, II and III Protective Coatings Applied to Nuclear Power Plants." Additionally, station procedures require a coating specialist to be qualified in accordance with ASTM D7167, "Standard Guide for Establishing Procedures to Monitor the Performance of Safety-Related Coating Service Level III Lining Systems," which is endorsed in Regulatory Guide 1.54, Revision 2.

Response to RAI B2.1.28-4(c):

As indicated in the response to request (a) above, inspection intervals will not exceed those specified in NUREG-2191, Table XI.M42-1, "Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers."

SLRA Revisions:

SLRA Section B2.1.28 and Table A4.0-1, Item 28 will be supplemented, as shown in Enclosure 5, to indicate the changes noted above.

RAI B2.1.28-5

Background:

As amended by letter dated April 2, 2019, SLRA Section B2.1.28, Enhancement No. 1 provides a list of components, including tanks, which will be inspected as part of the program. This list did not include the security diesel fuel oil tank, which is being managed for loss of material using the Fuel Oil Chemistry program.

As amended by letter dated April 2, 2019, SLRA Section B2.1.18, "Fuel Oil Chemistry," Exception No. 1 states the following regarding the security diesel fuel oil tank: "[t]he wall of the interior tank is provided with a solvent-based rust preventive film (not considered a coating)."

The "scope of program" program element of GALL-SLR Report XI.M42 recommends that internally coated tanks exposed to fuel oil, where loss of coating or lining integrity could prevent satisfactory accomplishment of any of the component's or downstream component's current licensing basis (CLB) intended functions, are included within the scope of the program.

Issue:

From information provided in the SLRA, it appears that if the "solvent-based rust preventative film" were to degrade due to age-related mechanisms, it might impact the intended function of the security diesel fuel oil tank, or downstream components (e.g., diesel injectors). Due to this, it appears that the "solvent-based rust preventative" should be included in the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program as per the recommendations of GALL-SLR Report AMP XI.M42.

The SLRA does not provide information on potential age-related failure modes for the "solvent-based rust preventative." The staff is unable to determine how it might degrade, and if this might impact the intended function of in-scope components. Different degradation mechanisms might impact the intended function of different components depending on if the film degrades into large sheets, small particles, etc.

Request:

1. *Based on potential age-related failure modes that could impact the intended function of the security diesel fuel oil tank, or downstream components, provide a basis for why the "solvent-based rust preventative film" was not included in the scope of the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program.*

2. *Additionally, describe any potential age-related failure modes of the "solvent-based rust preventative film," that might impact the intended function of the security diesel fuel oil tank, or downstream components.*

Dominion Response:

As identified in Section B2.1.18 of the SLRA, the security diesel generator fuel oil tank cannot be cleaned internally and is not accessible for internal inspection or bottom thickness measurements. Since the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) is a conditioning monitoring program which relies on inspections of the tank internal surfaces, it would not be an appropriate program to manage degradation of the solvent-based rust preventative film. However, the security diesel generator fuel oil tank is in the scope of the *Fuel Oil Chemistry* program (B2.1.18). As required by the *Fuel Oil Chemistry* program (B2.1.18), the security diesel generator fuel oil tank is sampled quarterly and the samples are analyzed for particulates consistent with ASTM D6217-98. Since the security diesel generator fuel oil tank was originally installed in 2011, quarterly test results noted below demonstrate fuel oil particulate levels have remained below the 10 mg/L acceptance limit over the installed life of the tank.

PARTICULATE CONTAMINATION (ASTM D6217-98)			
SAMPLE DATE	ACCEPTANCE CRITERIA	RESULT	SAT/UNSAT
12/14/2018	≤10 mg/L	1.9 mg/L	SAT
09/12/2018	≤10 mg/L	1.8 mg/L	SAT
06/14/2018	≤10 mg/L	1.6 mg/L	SAT

12/19/2017	≤10 mg/L	1.7 mg/L	SAT
09/19/2017	≤10 mg/L	2.0 mg/L	SAT
06/15/2017	≤10 mg/L	1.7 mg/L	SAT
03/24/2017	≤10 mg/L	2.1 mg/L	SAT
12/08/2016	≤10 mg/L	2.7 mg/L	SAT
09/09/2016	≤10 mg/L	1.6 mg/L	SAT
06/08/2016	≤10 mg/L	2.4 mg/L	SAT
03/08/2016	≤10 mg/L	2.4 mg/L	SAT
12/04/2015	≤10 mg/L	6.1 mg/L	SAT
09/18/2015	≤10 mg/L	1.91 mg/L	SAT
06/13/2015	≤10 mg/L	1.49 mg/L	SAT
03/16/2015	≤10 mg/L	3.30 mg/L	SAT
02/05/2015	≤10 mg/L	2.47 mg/L	SAT
11/06/2014	≤10 mg/L	1.90 mg/L	SAT
08/05/2014	≤10 mg/L	3.32 mg/L	SAT
02/04/2014	≤10 mg/L	2.20 mg/L	SAT
11/04/2013	≤10 mg/L	0.90 mg/L	SAT
08/09/2013	≤10 mg/L	0.68 mg/L	SAT
05/10/2013	≤10 mg/L	1.87 mg/L	SAT
02/13/2013	≤10 mg/L	1.10 mg/L	SAT
11/11/2012	≤10 mg/L	1.45 mg/L	SAT
08/14/2012	≤10 mg/L	1.47 mg/L	SAT
05/13/2012	≤10 mg/L	0.49 mg/L	SAT
11/17/2011	≤10 mg/L	0.26 mg/L	SAT

The security diesel generator engine's fuel oil filter is rated at 10 microns and filters particulates from the fuel oil supply line. The fuel oil is periodically replaced. A review of the corrective action program did not identify any operating experience related to clogged or dirty fuel oil filters for the security diesel generator since installation in 2011.

The *Fuel Oil Chemistry* program (B2.1.18) manages loss of material of the security diesel generator fuel oil tank to maintain the pressure boundary intended function during the subsequent period of extended operation. In addition, degradation of the film coating which results in increased particulates would be identified during sampling as part of the *Fuel Oil Chem*istry program (B2.1.18). Quarterly sampling of the diesel generator fuel oil tank and periodic replacement of the fuel oil filter provides reasonable assurance the pressure boundary intended function of the diesel generator fuel oil tank will be maintained and the fuel oil supply to the security diesel generator engine will not be adversely affected during the subsequent period of extended operation.

RAI B2.1.28-6

Background:

As amended by letter dated April 2, 2019, SLRA Section B2.1.28, Enhancement No. 7 states "[p]rocedures will be revised to require a pre-inspection review of the previous "two" condition assessment reports, when available, be performed, to review the results of inspections and any subsequent repair activities."

In addition to the statement above, GALL-SLR Report AMP XI.M42 states the following:

> *A coatings specialist prepares the post-inspection report to include: a list and location of all areas evidencing deterioration, a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where repair can be postponed to the next refueling outage, and where possible, photographic documentation indexed to inspection locations.*

Issue:

The staff seeks clarification for why Enhancement No. 7 does not include the GALL-SLR Report AMP XI.M42 recommendation regarding preparation of a post-inspection report by a coatings specialist.

Request:

State the basis for why Enhancement No. 7 does not include the GALL-SLR Report AMP XI.M42 recommendation regarding preparation of a post-inspection report by a coatings specialist.

Dominion Response:

Enhancement 7 does not include recommendations for a post inspection report because the Program procedures require preparation of a Coating Report Summary that includes the following information:

- List and location of all areas evidencing deterioration: The condition assessment will consist of locating and identifying coating indications, identifying the type of indication and documenting the information.

- Prioritization of the repair areas that must be repaired before returning the system to service: condition reports are submitted to document areas identified and assessed as deficient for repair or rework as required.

- Areas where repair can be postponed to the next refueling outage: If repairs cannot be performed immediately after discovery, then coating repairs are scheduled as soon as practical to maximize overall coating life. Repair of coating indications are scheduled at a time to properly perform the repairs. Extended deferrals of the repair work would be documented in condition reports.

- Where possible, photographic documentation indexed to inspection locations: An attachment to the coating summary report is prepared to document information and photographic images of coating walkdown areas, failures, and defects. Location, coating type, and indications noted would be documented. If inspection results are unsatisfactory, sketches and explanation of the unsatisfactory condition is provided.

RAI B2.1.28-7

Background:

SLRA Section B2.1.2.28 states that the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program will be consistent with GALL-SLR Report AMP XI.M42 with exception (not related to this RAI).

As amended by letter dated April 2, 2019, the "operating experience (OE) summary" section of SLRA Section B2.1.28 states, "[t]he component cooling heat exchanger channel heads are epoxy-coated carbon steel exposed to raw water (service water). Inspections are performed yearly, which allows early detection of degradation of coatings and underlying metal." The OE summary also states that an inspection of the 1B component cooling water heat exchanger inlet and outlet end bells in 2016 revealed 25 areas requiring coating repair and 3 locations requiring weld repair.

GALL-SLR Report Table XI.M42-1 recommends that internal coatings/lining for piping, piping components, heat exchangers, and tanks are inspected every 4 or 6 years based on the inspection category.

Issue:

It appears that based on the plant-specific OE, the component cooling heat exchangers are inspected more frequently than the guidance provided in GALL-SLR Report Table XI.M42-1, "Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping

Components, and Heat Exchangers." Given that the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program will be consistent with GALL-SLR Report AMP XI.M42, the frequency of inspections of the component cooling heat exchangers could exceed the annual inspection interval because the frequency of inspections is not reflected in the current licensing basis. There is no basis for why the annual inspection[s] of the component cooling heat exchangers is not reflected in the current licensing basis for the SPEO.

Request:

State the basis for why the annual inspection[s] of the component cooling heat exchangers is not reflected in the current licensing basis for the SPEO.

Dominion Response:

There is no current licensing basis requirement for annual inspection of the CCW heat exchangers but the technical basis for inspection on an annual frequency is to monitor flow blockage due to biological growth as a preventive measure, not degradation of the coatings. Flow blockage of the CCW heat exchangers is managed by the *Open-Cycle Cooling Water System* program (B2.1.11). The service water flow is reduced in colder months because the incoming water is much colder. The reduced service water flow velocities allow mud and sediments, which would tend to remain in suspension during periods of higher flow, to come out of suspension and contribute to fouling the tubes. Eventually, the tubes are fouled so much that full flowing the heat exchangers during testing does not improve conditions. Under the preventive maintenance program, scraping and cleaning the heat exchanger tubes is performed once per year in the winter months.

As a result, annual coating inspections are performed on an opportunistic basis during the biological growth preventive maintenance program.

B2.1.29-1

Background:

SRP-SLR Section 4.6.1 states, in part: "If a plant's code of record requires a fatigue parameter evaluation (fatigue analysis or fatigue waiver), then this analysis may be a time-limited aging analysis (TLAA) and should be evaluated in accordance with 10 CFR 54.21(c)(1) for the subsequent period of extended operation."

SRP-SLR Section 4.6.1.1 states, in part: "The ASME Code contains explicit requirements for fatigue parameter evaluations (fatigue analyses or fatigue waivers), which are TLAAs."

The "detection of aging effects" program element of GALL-SLR AMP XI.S1 states: "Where feasible appropriate Appendix J leak rate tests (GALL-SLR AMP XI.S4) capable of detection of cracking may be performed or credited in lieu of the supplemental surface examination; the type of leak test determined to be appropriate is identified with the basis for components for which the option is used."

SLRA Section B2.1.29, as amended by Change Notice 2 (SLRA supplement) dated April 2, 2019, states that the ASME Section XI, Subsection IWE AMP is an existing program that following enhancements will be consistent, with exception, to GALL-SLR Report AMP XI.S1, "ASME Section XI, Subsection IWE." SLRA Section B2.1.29 further states that the ASME Section XI, Subsection IWE AMP takes the following exception to the "parameters monitored or inspected" and "detection of aging effects" of GALL-SLR Report (NUREG-2191) AMP XI.S1:

NUREG-2191, Section XI.S1, ASME Section XI, Subsection IWE, recommends that steel, stainless steel, dissimilar metal weld pressure-retaining components that are subject to cyclic loading but have no CLB fatigue analysis, be monitored for cracking and supplemented with surface examination (or other applicable technique) in addition to visual examination to detect cracking. With the exception of high temperature components (e.g., high temperature penetrations), carbon steel components that are subject to cyclic loading (with no CLB fatigue analysis) are not monitored for cracking utilizing supplemental surface examinations."

As justification for the exception, the SLRA Section B2.1.29, as amended by Change Notice 2, states the following.

> *The containment contains dissimilar metal welds and steel components that are subject to cyclic loading but have no CLB fatigue analysis. The containment was designed in accordance with ASME Section III, Subsection N-415.1, 1968 edition. The six conditions [fatigue waiver] in ASME Section III, Subsection N- 415.1 were analyzed for the original design, initial license renewal, and subsequent license renewal to determine the need for a detailed fatigue analysis. Results of each analysis determined that a detailed fatigue analysis was not required for the containment liner due to stress fluctuations caused by temperature, pressure, and design earthquake cycles since all six conditions were shown to be satisfied.*

> *.....The containment liner fatigue analysis in Section 4.6 concluded that components that could be subject to cyclic loading, but have no current licensing basis fatigue analysis, are subjected to an acceptable and negligible amount of fatigue. Therefore, surface examinations will not be performed except for high temperature components that are subject to cyclic loading. ...*

From information in the SLRA, as amended, the proposed program exception appears to be applicable to carbon steel components of containment penetrations, hatches (personnel, equipment) and air locks, other than high temperature piping penetrations, dissimilar metal weld penetrations, and containment pressure-retaining portions of fuel transfer tube components.

Issue:

Contrary to the SLRA Change Notice statements noted above, SLRA Section 4.6.3 states: "There are no TLAAs for containment penetrations since these were not analyzed for cyclic fatigue." SLRA Section 3.5.2.2.1.5 also states that there are no TLAAs for containment penetrations. Further, SLRA Section 4.6.1 provides a TLAA disposition only for the containment liner plate. Additionally, Section 13 of Calculation 11448-EA-62, Addendum 00C, "Reactor Containment Liner Fatigue Evaluation for 80-Year Plant Life, Surry Unit 1 and Unit 2," Revision 0, notes that the conclusion therein is applicable to containment liner, mat and dome liners. The calculation does not appear to address any other containment pressure-retaining boundary components.

Based on the justification provided in the SLRA supplement for the exception, it appears that for those containment pressure-retaining boundary components subject to cyclic loading but that have no CLB fatigue analysis (i.e., no fatigue TLAA), there exists an ASME Section III, Subsection N-415.1 fatigue waiver analysis in the CLB which by definition would be a TLAA. The staff also notes that if a TLAA exists for these components, there is no need to take an exception to the GALL-SLR AMP. However, no fatigue TLAAs were submitted in the SLRA supplement for the components to which the exception applies as stated in the justification for the exception. The NRC staff is also unable to verify how the containment liner fatigue analysis in SLRA Section 4.6 concluded that [other] components that could be subject to cyclic loading, but have no CLB fatigue analysis, are subjected to an acceptable and negligible amount of fatigue, as claimed by Dominion.

The staff needs additional information to evaluate the adequacy of the SLRA Section B2.1.29 AMP to manage aging effects of cracking due to cyclic loading, specifically with *regard to the supporting justification for the related proposed exception to the SLRA AMP.*

Request:

1. *For each containment pressure-retaining boundary component to which the program exception applies based on the fatigue waiver assessment performed as stated in the SLRA Change Notice 2, provide in SLRA Section 4.6 (and related UFSAR supplement) a summary of the fatigue waiver assessment with results, transients considered, etc., and TLAA disposition that would demonstrate how the component met, for the subsequent period of extended operation, the six criteria for fatigue waiver stipulated in ASME Code Section III, Subsection N-415.1, 1968 edition.*

2. *Alternately, if a CLB fatigue waiver analysis does not exist as stated in SLRA Change Notice 2, either:*

   a. *provide the technical bases for the exception consistent with the fatigue waiver criteria in ASME Code Section III, Subsection N415.1, "Vessels Not Requiring Analysis for Cyclic Operation," that would demonstrate that the containment liner fatigue waiver analysis in SLRA Section 4.6.1 and its conclusion is applicable to each of the components to which the proposed program exception is intended to apply, or that the fatigue waiver criteria are individually met for each of these components;*

   b. *OR, in lieu of the exception, credit appropriate 10 CFR 50 Appendix J Type B local leak rate tests capable of detecting cracking due to cumulative fatigue damage from cyclic loading for each of the components to which the program exception is intended to apply .*

Dominion Response:

Response to RAI B2.1.29-1, Request 2 (Request 1 is not applicable):

The Containment contains components that are subject to cyclic loading but have no current licensing basis fatigue analysis. The containment liner, which includes the equipment hatch, was designed in accordance with ASME Section III, Subsection N-415.1, 1968 edition, and constructed of SA-442 Grade 60 steel or SA-516 Grade 60 FBX. The six conditions in ASME Section III, Subsection N-415.1 were analyzed for the original design, initial license renewal, and subsequent license renewal to determine the need for a detailed fatigue analysis of the containment liner. Results of the analyses determined that a detailed fatigue analysis was not required due to stress fluctuations caused by temperature, pressure, and design earthquake cycles since all six conditions were shown to be satisfied. Therefore, surface examinations will not be required for the containment liner.

The original fatigue waiver for the containment liner states that operating pressure variations can be expected to occur not more than 100 times during the plant lifetime (40 years). For design purposes, this was conservatively increased to 1000 cycles for the original 40 year life. For initial license renewal (60 years), this was extrapolated to 1500 cycles (Reference: UFSAR Section 15.5.1.8). As noted in Subsequent License Renewal Application Table 4.3.1-1, the accrued transient cycles as of 6/30/2016 for Unit 1 and Unit 2 were 121 (44.5 years) and 109 (43 years), respectively. Even if the existing cycles are doubled and projected to 80 years of operation, there is sufficient margin in the design cycles to justify retaining 1500 as the number of cycles used to evaluate the components for the subsequent period of extended operation (80 years).

For subsequent license renewal, the six conditions in ASME Section III, Subsection N-415.1 were analyzed for steel penetrations (with a maximum operating temperature less than 200°F) and stainless steel penetrations. The steel mechanical penetrations are constructed of SA-333 Grade 3 material, and the stainless steel penetrations are constructed of SA-312 Type 304 or Type 316 material. The electrical penetration sleeves are constructed of the same steel (SA-333 Grade 3) as the mechanical sleeves, and the electrical penetration flanges are constructed of SA-350 Grade LF2 steel. Results of these analyses determined that a detailed fatigue analysis was not required due to stress fluctuations caused by temperature, pressure, and design earthquake cycles since all six conditions were shown to be satisfied for each material. Therefore, surface examinations will not be required for these components.

The conditions specified in ASME Section III, Subsection N-415.1 to evaluate cyclic fatigue were applied to each of the materials used in the construction of the containment penetrations. The results of these evaluations are summarized below.

Condition 1) Atmospheric to operating pressure cycle

SA-442-Gr 60 and SA-516 Gr 60
N_{actual} = 1,500 cycles < N_{3Sm} = 2,500 cycles

SA-333 Gr 3
N_{actual} = 1,500 cycles < N_{3Sm} = 1,919 cycles

SA-350 Gr LF2
N_{actual} = 1,500 cycles < N_{3Sm} = 1,570 cycles

SA-312 Type 304 and Type 316
$N_{actual} = 1{,}500$ cycles $< N_{3Sm} = 2{,}000$ cycles

Condition 1 is satisfied

Condition 2) Normal operation pressure fluctuation

n_1 = maximum number of pressure cycles during normal operations
n_2 = maximum number of pressure cycles during Type A testing
N_1 = allowable number of pressure cycles during normal operations
N_2 = allowable number of pressure cycles during Type A testing

SA-442 Gr 60 and SA-516 Gr 60
$n_1/N_1 + n_2/N_2 = 2000/10^6 + 100/2000 = 0.052 < 1.0$

SA-333 Gr 3
$n_1/N_1 + n_2/N_2 = 2000/10^6 + 100/1416 = 0.073 < 1.0$

SA-350 Gr LF2
$n_1/N_1 + n_2/N_2 = 2000/10^6 + 100/1177 = 0.087 < 1.0$

SA-312 Type 304 and Type 316
$n_1/N_1 + n_2/N_2 = 2000/10^6 + 100/4000 = 0.027 < 1.0$

Condition 2 is satisfied for normal operation and Type A testing

Condition 3) Temperature difference – normal operation, startup and shutdown

SA-442-Gr 60, SA-516 Gr 60, SA-333 Gr 3, and SA-350 Gr LF2

$\Delta T_0 = 35°F < S_a/2E\alpha = 116°F$

SA-312 Type 304 and Type 316

$\Delta T_0 = 35°F < S_a/2E\alpha = 113°F$

Condition 3 is satisfied

Condition 4) Temperature difference change – normal operation

Significant temperature-difference fluctuations are defined as those that exceed the following:

SA-442-Gr 60, SA-516 Gr 60, SA-333 Gr 3, and SA-350 Gr LF2
$S_a/2E\alpha = 36°F$

SA-312 Type 304 and Type 316
$S_a/2E\alpha = 36.25°F$

Operating data show that none of the operating temperature fluctuations are expected to exceed 36°F; therefore no temperature-difference fluctuations are considered significant.

Condition 4 is satisfied

Condition 5) Temperature difference – dissimilar metals

Not applicable. Dissimilar metal welds will receive surface examinations.

Condition 6) Mechanical loads

S_{max} = maximum shear stress due to earthquake
S_a = stress for 40 cycles of design earthquake

SA-442-Gr 60, SA-516 Gr 60, SA-333 Gr 3, and SA-350 Gr LF2
$S_{max} = 6,104 \text{ psi} < S_a = 300,000 \text{ psi}$

SA-312 Type 304 and Type 316
$S_{max} = 6,104 \text{ psi} < S(a) = 430,000 \text{ psi}$

Condition 6 is satisfied

The above fatigue waiver analyses provide the technical bases for the exception consistent with the fatigue waiver criteria in ASME Code Section III, Subsection N415.1, "Vessels Not Requiring Analysis for Cyclic Operation." The fatigue waiver criteria are individually met for each of these components in terms of their materials of construction.

The *ASME Section XI, Subsection IWE* program, following enhancement as shown in Change Notice No. 2, will augment visual examinations with surface examinations to manage cracking in the Containment pressure retaining portions of the fuel transfer tube, fuel transfer tube enclosure, fuel transfer tube blind flange, dissimilar metal weld penetrations, and high-temperature steel piping penetrations that could be subject to cyclic loading but have no CLB fatigue analysis. Surface examinations will be performed once during each ten year interval. UFSAR Section 14B2.2.1 defines high-energy lines as those with a maximum operating temperature equal or exceeding 200°F. UFSAR Table 14B-2 provides a listing of the high-energy lines, their maximum operating temperatures, and their locations. The high temperature penetrations for the lines identified in Table 14B-2 that are located in Containment will be monitored for cracking with supplemental surface examinations (or other applicable technique) in addition to visual examination.

10 CFR 50, Appendix J, Type B local leak rate tests capable of detecting cracking due to cumulative fatigue damage from cyclic loading are performed for the airlocks, as described in UFSAR Sections 5.5.4 and 5.5.6. Therefore, surface examinations are not , required for these components.

The existing *ASME Section XI, Subsection IWE* program (B2.1.29), following enhancement as shown in Change Notice No. 2, and the *10 CFR Part 50, Appendix J* program (B2.1.32) are adequate to manage cracking of Containment pressure boundary components that are subject to cyclic loading but have no current licensing basis fatigue analysis.

<u>SLRA Revision:</u>

SLRA Table 4.6.1-1 is supplemented, as shown in Enclosure 5, to indicate 1500 design cycles are acceptable for evaluating the above components for the subsequent period of extended operation (80 years).

<u>RAI B2.1.33-1</u>

<u>Background:</u>

SLRA Section B2.1.33, "Masonry Walls" states that "[T]he Masonry Walls program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.S5, Masonry Walls." Enhancements are revisions or additions to existing AMPs that the applicant commits to implement prior to the subsequent period of extended operation. Enhancements include, but are not limited to, those activities needed to ensure consistency with the GALL-SLR Report recommendations. Enhancements may expand, but not reduce, the scope of an AMP.

The "acceptance criteria" element of GALL-Report AMP XI.S5 "Masonry Walls," states in part: "For each masonry wall, observed degradation......are assessed against the evaluation basis to confirm that the degradation has not invalidated the original evaluation assumptions or impacted the capability to perform the intended functions."

<u>Issue:</u>

The staff is unable to verify Dominion's claim of consistency of the "acceptance criteria" element of SLRA AMP B2.1.33 with the corresponding element of GALL Report AMP XI.S5 due to the following issue:

Enhancement 2 to SLRA AMP B2.1.33 attributed to the "Monitoring and Trending" program element states, in part: "....[T]he procedure will be revised to include acceptance criteria for masonry wall inspections that will be used to ensure observed aging effects (cracking, loss of material, or gaps between the structural steel supports and masonry walls) do not invalidate the evaluation basis of the wall or impact its intended function." The staff notes that, in order to be consistent with the "acceptance criteria" program element of GALL-SLR AMP XI.S5, the portion of SLRA Enhancement 2 described above should apply to the "acceptance criteria" program element of SLRA AMP B2.1.33.

Request:

Clarify whether Enhancement 2 or portion of it applies to the "acceptance criteria" program element. If not, justify how the "acceptance criteria" program element of the SLRA AMP will be consistent with that of the GALL-SLR AMP XI.S5.

Dominion Response:

Dominion letter dated June 10, 2019 (S/N 19-248), previously provided the response to the request in RAI B2.1.33-1. No further action is required to respond to this request.

RAI B2.1.36-1

Background:

In its SLRA, Section B2.1.36, "Protective Coating Monitoring and Maintenance," the applicant claimed consistency with the "monitoring and trending" program element of GALL-SLR Report AMP XI.S8, "Protective Coating Monitoring and Maintenance" and also stated that degraded and unqualified coatings will be controlled and assessed to ensure the quantity of degraded and unqualified coatings does not affect the intended function of the Emergency Core Cooling System (ECCS) suction strainers. Additionally, ETE-SLR-2018-1341, "Surry Subsequent License Renewal Project – Aging Management Program Evaluation Report – Protective Coating Monitoring and Maintenance," Revision 0, describes how the quantity of the degraded and unqualified coatings are controlled and assessed.

The "monitoring and trending," program element recommends that the program assesses the total amount of degraded coatings and compare it with the total amount of permitted degraded coatings to provide reasonable assurance of post-accident operability of the ECCS.

Issue:

In ETE-SLR-2018-1341, it states that "...the coatings margin does not need to be preserved and may be utilized by the GSI-191 Program to maintain inventory control." However, not maintaining the coatings margin may challenge the limits of the ECCS suction strainer and its ability to function in a postulated post-accident scenario.

Request:

Explain the statement that the coatings margin does not need to be preserved, and how this demonstrates consistency with the "monitoring and trending" element which recommends comparison of the amount of degraded coatings to the amount of permitted degraded coatings in order to provide reasonable assurance of post-accident operability of the ECCS.

Dominion Response:

ETE-SLR-2018-1341 will be revised to remove the statement, "Therefore, the coatings margin does not need to be preserved and may be utilized by the GSI-191 Program to maintain inventory control."

The quantity of degraded and unqualified coatings identified is assessed to ensure the quantity does not affect the intended function of the Emergency Core Cooling System suction strainers. An inventory of unqualified coatings is maintained by tracking of the debris volume in supporting calculations. If the coating activities remove or replace unqualified coatings, or add qualified coatings to the overall inventory in containment, the GSI-191 Program Site Owner assures the change is in accordance with site specific procedures governing changes in containment coating inventory regarding GSI-191 design basis.

RAI B2.1.36-2

Background:

The proposed UFSAR supplement for the Protective Coating Monitoring and Maintenance program in Section A1.36 of the SLRA was modified by letter dated April 2, 2019. This modification included removal of part of the proposed UFSAR supplement describing coating system selection, application, visual inspections, assessments, and repairs of Service Level (SL) I coatings. It was replaced with text that describes the maintenance and monitoring of SL I coatings. The text in both versions of the proposed

UFSAR supplement discusses Regulatory Guide (RG) 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants."

GALL-SLR Table XI-01 provides the recommended UFSAR supplement for the Protective Coating Monitoring and Maintenance program and recommends that the "...program consists of guidance for selection, application, inspection, and maintenance of protective coatings."

Issue:

Although the proposed UFSAR supplement in the SLRA, as amended, clarifies that certain program activities will be conducted consistent with RG 1.54, it now appears to exclude certain program activities that are described in the recommended UFSAR supplement in the GALL-SLR. Specifically, the GALL-SLR recommends that the program contain guidance for selection, application, and inspection of coatings. However, the UFSAR supplement in the April 2nd letter removes these aspects of the program from the proposed UFSAR supplement.

Request:

Explain why the proposed UFSAR supplement does not address selection, application, and inspection of SL I coatings, even though these are addressed in the recommended GALL-SLR UFSAR supplement.

Dominion Response:

The following sentence will be added as the last sentence to the first paragraph of the SLRA Appendix A1.36, Protective Coating Monitoring and Maintenance program:

> "The program consists of guidance for selection, application, inspection, and maintenance of protective coatings."

SLRA Revision:

SLRA Section A1.36 is supplemented, as shown in Enclosure 5, to indicate the change noted above.

RAI B3.2-1

Background:

The GALL-SLR Report aging management program (AMP) X.M2 "Neutron Fluence Monitoring" states that the scope of the program includes reactor pressure vessel (RPV) and reactor vessel internals (RVI) components. Subsequent license renewal application (SLRA) Section B3.2 "Neutron Fluence Monitoring" describes the applicant's AMP for monitoring neutron fluence of RPV and RVI components. The applicant states that the neutron fluence monitoring program in SLRA Section B3.2 is an existing program consistent with the program elements defined in the GALL-SLR Report AMP X.M2. The applicant summarized the AMP in the UFSAR supplement in SLRA Section A2.2 "Neutron Fluence Monitoring."

Issue:

In SLRA Table C2.2-1, the applicant provided the neutron fluence ranges for RVI component-specific locations analyzed in the MRP-227 program gap analysis. However, these cited 80-year fluence ranges are based only on EPRI's generic expert panel analysis for the components and the listed ranges do not represent Surry-specific values for the component locations at 68 EFPY. The staff is unable to verify that the site-specific neutron fluence values for the referenced RVI components are within the ranges cited for the components in the gap analysis because: (a) the SLRA does not include any Surry-specific fluences for the components at 68 EFPY, and (b) SRLA AMP B3.2 has yet to credit any neutron fluence monitoring activities for achieving this objective as part of SLRA AMP B3.2.

Request:

Clarify whether component-specific neutron fluence values for the RVI components within the scope of the MRP-227 gap analysis have been projected to 80 years of licensed operations. If so, provide the 80-year neutron fluence values for the components. Otherwise, if 80-year component-specific projections have not been performed, explain how confirmation of neutron fluence levels will be performed for Surry-specific RVI components to verify that the neutron fluence values for the components will be within the component-specific ranges listed in Footnote "a" of SLRA Table C2.2-1.

Dominion Response:

WCAP-18205-NP, "Reactor Internal Fluence Evaluation for a Westinghouse 3-Loop Plant With Twin Units - Subsequent License Renewal", describes an 80 year (72 EFPY) neutron fluence assessment on reactor internals performed for a Westinghouse 3- Loop plant with two units in support of subsequent licensing renewal based on the guidance specified in Regulatory Guide 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence".

Table 2.2-1 and Table 2.2-2 in WCAP-18205-NP present the DORT code transport calculations in the analysis in comparison with the previous transport calculations in WCAP-18028-NP, "Extended Beltline Pressure Vessel Fluence Evaluations Applicable to Surry Units 1 and 2," at the pressure vessel inner surface at the beltline region. The comparisons in Table 2.2-1 and Table 2.2-2 demonstrate that the results presented in WCAP-18205 are consistent with those used for reactor vessel integrity for 54 EFPY and 72 EFPY.

WCAP-18353-NP, "Reactor Internals Fluence Evaluation for a Westinghouse 3-loop Plant with Two Units - Subsequent License Renewal," modified the WCAP-18205-NP reactor internals models to provide a more detailed geometry including the upper internals geometry needed for this analysis. Using the updated models, radiation transport calculations have been performed on a fuel-cycle-specific basis, using fuel cycle information specific to Surry to calculate reactor internals fast neutron fluences. In WCAP-18353-NP, neutron exposures expressed in terms of fast neutron (e> 1.0 MeV) fluence were established for the reactor internals of Unit 1 at 51.6 EFPY and 72 EFPY and for the rector internals of Unit 2 at 52.8 EFPY and 72 EFPY. WCAP-18353-NP determined which fast neutron fluence range (E > 1.0 MeV) applies to each reactor internals component and supports binning of the selected Westinghouse 3-Loop plant units' reactor internals components for MRP-191, "Materials Reliability Program: Screening, Categorization, and Ranking of Reactor Internals Components for Westinghouse and Combustion Engineering PWR Design (MRP-191)", screening purposes. Screening criteria for fast neutron fluence are taken from the updated MRP-191, which are consistent with MRP-175, "Materials Reliability Program: PWR Internals Material Aging Degradation Mechanism Screening and Threshold Values (MRP-175)":

- 1.3×10^{20} n/cm^2 (per MRP-175, screening threshold for stress relaxation in bolts)
- 6.7×10^{20} n/cm^2 (per MRP-175, screening threshold IE in CASS)
- 1.0×10^{21} n/cm^2 (per MRP-175, screening threshold for IE in austenitic stainless steel)
- 2.0×10^{21} n/cm^2 (per MRP-175, minimum dose for IASCC (requires 89 ksi stress))
- 1.3×10^{22}n/cm^2 (per MRP-175, screening threshold for void swelling)

The reactor internals components at the selected Westinghouse 3-Loop plant Units 1 and 2 were reviewed and compared against the fluence maps presented in Sections 2.3

(60 years) and 2.4 (80 years) of WCAP-18353-NP. The fluence results were used for subsequent screening, FMECA, functionality analysis, and categorization for the 60 years (51.6/52.8 EFPY) and 80 years operation (72 EFPY) in support of SLR. The results are presented in WCAP-18353-NP, Table 2.6-1 through 2.6-4 where X's mark the Surry plant specific component fluence ranges and O"s mark the industry component fluence ranges from MRP 2017-038, Transmittal of Preliminary Results from MRP191 Expert Panel in Support of Subsequent License Renewal at U.S. PWR Plants. The fluence maps for 51.6 EFPY and 72 EFPY for Unit 1 and the fluence maps for 52.8 EFPY and 72 EFPY for Unit 2 are similar, as can be seen by comparing the figures in WCAP-18353-NP, Section 2.3 and 2.4. The evaluated fluence levels for the various components are the same between 51.6 EFPY for Unit 1 and the same between 52.8 EFPY and 72 EFPY for Unit 2, except for the following components:

- Control Rod Assemblies and Flow Downcomers Subassembly
  See Table C2.2-1: Guide Tube Support Pins (Region 4), and Support Pin Nuts (region 4)
- Upper Support Column Assemblies Subassembly
  See Table C2.2-1: Column Bases (region 4)
- Baffle and Former Assembly
  See Table C2.2-1: Baffle Plates (region 6) and Former Plates (region 6)
- Bottom Mounted Instrumentation (BMI) Column Assemblies
  See Table C2.2-1; BMI Column Collars (region 5)
- Lower Core Plate and Fuel Alignment Pins
  See Table C2.2-1: Lower Core Plate (region 5)
- Neutron Panels / Thermal Shield:
  See Table C2.2-1: Thermal Shield or neutron panels (region 4)

WCAP-18353-NP Table 2.5-1and Table 2.5-2 document the figures of merit (FOM) and power densities of the selected Westinghouse 3-Loop plant units 1 and 2 for the purpose of MRP-227-A applicability evaluation. The analysis results presented in Table 2.5-1 and Table 2.5-2 assumed Unit 1 fuel Cycle 21 through Cycles 24 and Unit 2 fuel Cycle 20 through Cycles 23 had a rated power of 2940 MWt.

The reactor internals components at the selected Westinghouse 3-Loop plant Units 1 and 2 were reviewed and compared against the fluence maps presented in Sections 2.4 and 2.5 of WCAP-18205-NP. The fluence results were used for subsequent screening, failure mode, effects and criticality analysis (FMECA), functionality analysis, and categorization for the 60 years (54 EFPY) and 80 years operation (72 EFPY) in support of SLR. The fluence maps for 54 EFPY and 72 EFPY are similar, as can be seen by comparing the figures in WCAP-18205-NP, Sections 5.6 and 5.7. The evaluated fluence levels for the various components are the same between 54 EFPY and 72 EFPY, except for the following components:

- Control Rod Assemblies and Flow Downcomers Subassembly
  See Table C2.2-1: C-tubes (region 3), Flanges-Lower (region 4), Sheaths (region 3), and Support Pin Nuts (region 4)
- Mixing Devices Subassembly
  See Table C2.2-1: Mixing devices (region 4)
- Upper Support Column Assemblies Subassembly
  See Table C2.2-1: Bolts (at upper core plate)(region 4), Lock Keys (at upper core plate (region 3)

WCAP-18028-NP, Table 2.6-1 and Table 2.6-2 document the figures of merit and power densities of the selected Westinghouse 3-Loop plant Units 1 and 2 for the purpose of MRP-227-A applicability evaluation. WCAP-18028-NP assumed fuel cycles 23 through 26 for both units have a full power of 2587 MWt. While the fluence calculations in WCAP-18205-NP used the actual power, 2546 MWt for Cycle 23, and 2597 MWt for Cycle 24 and beyond for both units.

Enclosure 3

NON-PROPRIETARY RESPONSE TO RAIs 4.7.3-2 and 4.7.3-3 SET 1 REGARDING SPS SLRA

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

NON-PROPRIETARY RESPONSE TO RAIs 4.7.3-2 and 4.7.3-3 SET 1 REGARDING SPS SLRA

RAI 4.7.3-2

Background:

SLRA Section 4.7.3 addresses a TLAA on leak-before break (LBB) for the reactor coolant system (RCS) primary loop. Dominion (applicant) indicated the LBB analysis for 80 years of operation is documented in WCAP-15550, Revision 2. Section 7 of WCAP-15550, Revision 2 includes the elastic-plastic fracture mechanics analysis based on local failure mechanism to determine crack stability as part of the LBB analysis.

Issue:

Table 7-1 of WCAP-15550, Revision 2 indicates that the J_{app} value (applied J-integral) of critical location 3 (hot leg) is greater than that of critical location 6 (crossover leg). In contrast, the axial force (including pressure loading) and moment for critical location 3 are lower than those for critical location 6, respectively, as described in Figures 7-3 and 7-4. Specifically, axial force F = 1639 kips and moment M = 12918 in-kips for location 3, while F = 1870 kips and M = 15673 in-kips for location 6. Therefore, the staff needs additional information as to why the applied J-integral for location 3 is greater than that of location 6 in consideration of the load levels discussed above.

Request:

Explain why the applied J-integral for location 3 is greater than that of location 6 even though the axial force and moment of location 3 are less than those of location 6, respectively. As part of the response, provide the K_t (stress intensity factor for axial tension) and K_b (stress intensity factor for bending) for each of locations 3 and 6, as the plastic zone corrections are applied (refer to Reference 7-3 of the WCAP report, which is NUREG/CR-3464, Section II-1, H. Tada paper).

Dominion Response:

Locations 3 and 6 each use a slightly different approach for the J-integral calculation. For location 3, it is shown that the [effective stress (σ_{eff}) is less than the material yield strength. As such, the evaluation used an effective Linear-Elastic Fracture Mechanics (LEFM) calculation to determine the tension stress intensity factor, K_t), the bending stress intensity factor (K_b), and the corresponding applied J-integral value (J_{app} = [ ]. a,c,e

For the 80-year license renewal J_{app} for location 6 was re-calculated using the [ ]^{a,c,e}, resulting in a J_{app} value of [ ]^{a,c,e}. As expected, this value is higher than the J_{app} value for location 3, which is [ ]^{a,c,e}. However, the previous calculated [ ]^{a,c,e} J_{app} = [ ]^{a,c,e} for location 6 exceeds the material allowable of J_{Ic} with the consideration of thermal aging calculated per NUREG/CR-4513, Revision 2. Because [ ]^{a,c,e} was too conservative at this location, a more representative [ ]^{a,c,e} was used in order to obtain both the J_{app} value and the applied tearing modulus (T_{app}) in order to demonstrate that $T_{app} < T_{mat}$.

In WCAP-15550, Revision 2, [ ]^{a,c,e} is performed [ ]^{a,c,e} to calculate J_{app} for Location 6. The use of [ ]^{a,c,e} is identified as the reason why the applied J-integral for location 6 is less than the applied J-integral for location 3, where location 3 uses [ ]^{a,c,e}. If the [ ]^{a,c,e} were applied at location 3, it would be expected that the resulting J_{app} value would be less than the value reported for location 6 [ ]^{a,c,e}.

RAI 4.7.3-3

<u>Background:</u>

SLRA Section 4.7.3 addresses a TLAA on leak-before break (LBB) for the reactor coolant system (RCS) primary loop. Dominion (applicant) indicated the LBB analysis for 80 years of operation is documented in WCAP-15550, Revision 2. Section 8 addresses the fatigue crack growth analysis to confirm that the potential fatigue crack growth does not affect the integrity of the primary loop piping and the crack stability determined in the LBB analysis.

<u>Issue:</u>

The staff noted that the fatigue crack growth analysis does not clearly discuss the following: (1) the aspect ratio of the postulated initial crack sizes; and (2) the basis for the initial crack sizes for the fatigue analysis.

<u>Request:</u>

Provide the following information: (1) the aspect ratio of the postulated initial crack sizes; and (2) the basis for the initial crack sizes for the fatigue analysis. As part of the response, clarify whether the initial crack depths are greater than those that are acceptable in accordance with the acceptance criteria of ASME Code, Section XI, *inservice inspection requirements (e.g., Table IWB-3410-1). If not, explain why the analysis assumes initial cracks that are not large enough to be detected and repaired during the inservice inspection.*

Dominion Response:

Note that the fatigue crack growth (FCG) analysis is not a requirement for the LBB analysis (Federal Register/Vol. 52, No. 167/Friday August 28, 1987/Notices, pp. 32626-32633) since the LBB analysis is based on the postulation of a through-wall flaw, whereas the FCG analysis is performed based on the surface flaw. In addition, the staff has indicated, "the Commission deleted the fatigue crack growth analysis in the proposed rule. This requirement was found to be unnecessary because it was bounded by the crack stability analysis," (Federal Register/Vol. 52, No. 207/Tuesday, October 27, 1987/Rules and Regulations, pp. 41288-41295).

Nevertheless, the FCG in WCAP-15550, Revision 2, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Surry Units 1 and 2 Nuclear Power Plants for the Subsequent License Renewal Program (80 Years) Leak-Before-Break Evaluation," was documented and retained to keep with historical precedence to demonstrate that small surface flaws will not result in a through-wall flaw over the design life of the plant. The aspect ratio for the postulated initial crack sizes are for a typical flaw shape of [ ]^{a,c,e} (flaw length/flaw depth). Various initial flaw depths were considered in the FCG analysis to demonstrate that small, NDE detectable flaw sizes on the order of [ ]^{a,c,e} would be acceptable for the life of the plant (i.e., would not grow to become complete through-wall).

The intent of FCG in the LBB analysis was not to use initial flaw depths that are larger than the Acceptance Tables of ASME Section XI IWB-3410-1, but rather to show a defense-in-depth fatigue crack growth based on small flaw sizes that are detectable based on NDE examination techniques, which would not become through-wall flaws over the design life of the plant.

Enclosure 4

CAW-19-4897, WESTINGHOUSE AFFIDAVIT FOR WITHHOLDING PROPRIETARY INFORMATION, DATED JUNE 4, 2019

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

AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA:
COUNTY OF BUTLER:

(1) I, Camille T. Zozula, have been specifically delegated and authorized to apply for withholding and execute this Affidavit on behalf of Westinghouse Electric Company LLC (Westinghouse).

(2) I am requesting the proprietary portions of LTR-SDA-II-19-35-P be withheld from public disclosure under 10 CFR 2.390.

(3) I have personal knowledge of the criteria and procedures utilized by Westinghouse in designating information as a trade secret, privileged, or as confidential commercial or financial information.

(4) Pursuant to 10 CFR 2.390, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure should be withheld.

(i) The information sought to be withheld from public disclosure is owned and has been held in confidence by Westinghouse and is not customarily disclosed to the public.

(ii) Public disclosure of this proprietary information is likely to cause substantial harm to the competitive position of Westinghouse because it would enhance the ability of competitors to provide similar technical evaluation justifications and licensing defense services for commercial power reactors without commensurate expenses. Also, public disclosure of the information would enable others to use the information to meet NRC requirements for licensing documentation without purchasing the right to use the information.

AFFIDAVIT

(5) Westinghouse has policies in place to identify proprietary information. Under that system, information is held in confidence if it falls in one or more of several types, the release of which might result in the loss of an existing or potential competitive advantage, as follows:

(a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.

(b) It consists of supporting data, including test data, relative to a process (or component, structure, tool, method, etc.), the application of which data secures a competitive economic advantage (e.g., by optimization or improved marketability).

(c) Its use by a competitor would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing a similar product.

(d) It reveals cost or price information, production capacities, budget levels, or commercial strategies of Westinghouse, its customers or suppliers.

(e) It reveals aspects of past, present, or future Westinghouse or customer funded development plans and programs of potential commercial value to Westinghouse.

(f) It contains patentable ideas, for which patent protection may be desirable.

(6) The attached documents are bracketed and marked to indicate the bases for withholding. The justification for withholding is indicated in both versions by means of lower case letters (a) through (f) located as a superscript immediately following the brackets enclosing each item of information being identified as proprietary or in the margin opposite such information. These lower case letters

AFFIDAVIT

refer to the types of information Westinghouse customarily holds in confidence identified in Sections (5)(a) through (f) of this Affidavit.

I declare that the averments of fact set forth in this Affidavit are true and correct to the best of my knowledge, information, and belief.

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

Executed on: 04 Jun 2019

Camille T. Zozula, Manager
Infrastructure & Facilities Licensing

PROPRIETARY INFORMATION NOTICE

Transmitted herewith are proprietary and non-proprietary versions of a document, furnished to the NRC in connection with requests for generic and/or plant-specific review and approval.

In order to conform to the requirements of 10 CFR 2.390 of the Commission's regulations concerning the protection of proprietary information so submitted to the NRC, the information which is proprietary in the proprietary versions is contained within brackets, and where the proprietary information has been deleted in the non-proprietary versions, only the brackets remain (the information that was contained within the brackets in the proprietary versions having been deleted). The justification for claiming the information so designated as proprietary is indicated in both versions by means of lower case letters (a) through (f) located as a superscript immediately following the brackets enclosing each item of information being identified as proprietary or in the margin opposite such information. These lower case letters refer to the types of information Westinghouse customarily holds in confidence identified in Sections (4)(ii)(a) through (4)(ii)(f) of the Affidavit accompanying this transmittal pursuant to 10 CFR 2.390(b)(1).

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Enclosure 5

SLRA MARK-UPS –SET 1 RAIs

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

[3.1.1-008] – The evaluation of fatigue is a TLAA for stainless steel, steel (with nickel alloy or stainless steel cladding) or nickel alloy steam generator components exposed to reactor coolant in the Reactor Vessel, Internals, and Reactor Coolant System, and is discussed in Section 4.3.2.6, "Steam Generators."

[3.1.1-009] – The evaluation of fatigue is a TLAA for stainless steel or steel (with stainless steel cladding or insert) reactor coolant pressure boundary components exposed to reactor coolant in the Reactor Vessel, Internals, and Reactor Coolant System, and is discussed in Section 4.3.1, "Transient Cycle Projections for 80 Years," and for stainless steel reactor coolant system primary loop piping, in Section 4.3.3 "ANSI B31.1 Allowable Stress Analyses," and in Section 4.7.3 "Leak-Before-Break."

[3.1.1-010] – The evaluation of fatigue is a TLAA for steel (with stainless steel cladding), stainless steel, or nickel alloy reactor vessel components exposed to reactor coolant in the Reactor Vessel, Internals, and Reactor Coolant System, and is discussed in Section 4.3.2.4, "Reactor Vessel."

[3.1.1-011] – The evaluation of fatigue is a TLAA for steel pump and valve closure bolting exposed to high temperatures and thermal cycles in the Reactor Vessel, Internals, and Reactor Coolant System, and is discussed in Section 4.3.1, "Transient Cycle Projections for 80 Years."

3.1.2.2.2 Loss of Material due to General, Pitting, and Crevice Corrosion

(1) Loss of material due to general, pitting, and crevice corrosion could occur in the steel PWR SG upper and lower shell and transition cone exposed to secondary feedwater and steam. The existing program relies on control of water chemistry to mitigate corrosion and inservice inspection (ISI) to detect loss of material. The extent and schedule of the existing SG inspections are designed to ensure that flaws cannot attain a depth sufficient to threaten the integrity of the welds. However, according to NRC Information Notice (IN) 90-04, "Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators," the program may not be sufficient to detect pitting and crevice corrosion if general and pitting corrosion of the shell is known to exist. Augmented inspection is recommended to manage this aging effect. Furthermore, this issue is limited to Westinghouse Model 44 and 51 Steam Generators, where a high-stress region exists at the shell to transition cone weld. Acceptance criteria are described in Branch Technical Position (BTP) RLSB-1 (Appendix A.1 of this SRP-SLR).

[3.1.1-012] – Loss of material due to general, pitting, and crevice corrosion could occur in the steel PWR SG upper and lower shell and transition cone exposed to secondary feedwater and steam. Information Notice 90-04, “Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators,” stated that volumetric examinations (UT) of the shell-to-transition-cone girth welds, required by Section XI of the ASME Code, may not be sufficient to differentiate isolated cracks from inherent geometric conditions. Following this notice, in addition to inspections required by ASME XI, a SPS steam generator transition cone girth weld was 100 percent MT inspected. No degradation indications were observed during these inspections. The continued implementation of the Water Chemistry (B2.1.2) program and the steam generator periodic inspections required by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program will effectively manage loss of material for the steam generator upper and lower shell and transition cone exposed to secondary feedwater and steam prior to loss of intended function.

(2) Loss of material due to general, pitting, and crevice corrosion could occur in the steel PWR steam generator shell assembly exposed to secondary feedwater and steam. The existing program relies on control of secondary water chemistry to mitigate corrosion. However, some applicants have replaced only the bottom part of their recirculating SGs, generating a cut in the middle of the transition cone, and, consequently, a new transition cone closure weld. It is recommended that volumetric examinations be performed in accordance with the requirements of ASME Code Section XI for upper shell and lower shell-to-transition cones with gross structural discontinuities for managing loss of material due to general, pitting, and crevice corrosion in the welds for Westinghouse Model 44 and 51 SGs, where a high-stress region exists at the shell to transition cone weld.

The new continuous circumferential weld, resulting from cutting the transition cone as discussed above, is a different situation from the SG transition cone welds containing geometric discontinuities. Control of water chemistry does not preclude loss of material due to pitting and crevice corrosion at locations of stagnant flow conditions. The new transition area weld is a field weld as opposed to having been made in a controlled manufacturing facility, and the surface conditions of the transition weld may result in flow conditions more conducive to initiation of general, pitting, and crevice corrosion than those of the upper and lower transition cone welds. Crediting of the ISI program for the new SG transition cone weld may not be an effective basis for managing loss of material in this weld, as the ISI criteria would only perform a VT-2 visual leakage examination of the weld as part of the system leakage test performed pursuant to ASME Code Section XI requirements. In addition, ASME Code Section XI does not require licensees to remove insulation when performing visual examination on nonborated treated water systems. Therefore, the effectiveness of the chemistry control program should be verified to ensure that loss of material due to general, pitting and crevice corrosion is not occurring.

For the new continuous circumferential weld, further evaluation is recommended to verify the effectiveness of the chemistry control program. A one-time inspection at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or an aging effect is progressing very slowly, such that the component's intended function will be maintained during the subsequent period of extended operation. Furthermore, this issue is limited to replacement of recirculating SGs with a new transition cone closure weld.

[3.1.1-012] – Loss of material due to general, pitting, and crevice corrosion could result in the steel PWR steam generator upper and lower shell and transition cone exposed to secondary feedwater and steam. The steam generators were replaced at SPS in 1981 for Unit 1 and in 1980 for Unit 2. Only the lower shell assembly of the steam generator (Westinghouse Model 51F) was replaced, generating a cut in the middle of the transition cone and consequently creating a new transition cone closure weld. For this new transition cone closure weld, a one-time inspection at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or an aging effect is progressing very slowly, such that the component's intended function will be maintained during the subsequent period of extended operation. ~~The One-Time Inspection (B2.1.20) program will perform a magnetic particle test inspection of the continuous circumferential transition cone closure weld on each steam generator (minimum 25 percent examination coverage of each weld) prior to the subsequent period of extended operation.~~For subsequent license renewal, the periodic examinations of the steam generator transition cone girth welds will continue to be performed as described in AMP B2.1.1, ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD, program. Consistent with NUREG-2192, Section 3.1.2.2.2, a one-time inspection will be performed for the transition cone closure weld on each steam generator using MT as described in the One-Time Inspection program (B2.1.20). This one-time inspection will confirm the effectiveness of the Water Chemistry program (B2.1.2) For the transition cone closure weld on each steam generator, the one-time MT inspection is intended to cover essentially 100% of the total weld length. This one-time inspection along with the continued implementation of the Water Chemistry (B2.1.2) program and the steam generator periodic inspections required by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program will effectively manage loss of material for the steel steam generator components prior to loss of intended function.

3.1.2.2.3 Loss of Fracture Toughness due to Neutron Irradiation Embrittlement

(1) Neutron irradiation embrittlement is a TLAA to be evaluated for the subsequent period of extended operation for all ferritic materials that have a neutron fluence greater than 10^17 n/cm^2 (E >1 MeV) at the end of the subsequent period of extended operation. Certain aspects of neutron irradiation embrittlement are TLAAs as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in Section 4.2, "Reactor Pressure Vessel Neutron Embrittlement Analysis," of this SRP-SLR.

[3.1.1-013] – Neutron irradiation embrittlement is a TLAA as defined in 10 CFR 54.3 and is evaluated in Section 4.2, Reactor Vessel Neutron Embrittlement Analysis.

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

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-103	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to soil, concrete	Cracking due to chemical reaction, weathering, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, or scaling	AMP XI.M41, Buried and Underground Piping and Tanks	No	Consistent with NUREG-2191~~.~~, with a different program credited. The Open Cycle Cooling Water System (B2.1.11) program will manage cracking and loss of material of the external surfaces of buried cementitious piping.
3.3.1-104	HDPE, fiberglass piping, piping components exposed to soil, concrete	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture	AMP XI.M41, Buried and Underground Piping and Tanks	No	Consistent with NUREG-2191.
3.3.1-107	Stainless steel, nickel alloy piping, piping components exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, Buried and Underground Piping and Tanks	No	Consistent with NUREG-2191.
3.3.1-108	Titanium, super austenitic, copper alloy, stainless steel, nickel alloy piping, piping components, tanks, closure bolting exposed to soil, concrete, underground	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC (super austenitic, copper alloy, stainless steel, nickel alloy; soil environment only)	AMP XI.M41, Buried and Underground Piping and Tanks	No	Consistent with NUREG-2191.
3.3.1-109	Steel piping, piping components, closure bolting exposed to soil, concrete, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, Buried and Underground Piping and Tanks	No	Consistent with NUREG-2191.

Table 3.3.2-5 Auxiliary Systems - Circulating Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Concrete	(I) Raw water	Cracking; loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-250	3.3.1-030	B
			(E) Soil	Cracking; loss of material	~~Buried and Underground Piping and Tanks (B2.1.27)~~Open-Cycle Cooling Water System (B2.1.11)	VII.I.AP-157	3.3.1-103	~~A~~E, 9
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 3
		Steel with internal coating	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Concrete	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-416	3.3.1-138	A, 1
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-400	3.3.1-127	E, 6
						VII.C1.A-414	3.3.1-139	A
		Steel with internal lining	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-416	3.3.1-138	A
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-414	3.3.1-139	A, 2

Table 3.3.2-5 Auxiliary Systems - Circulating Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Spray shield	FLB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	C, 7
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	C, 7
Valve body	LB;PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-47	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-271	3.3.1-093	A
		Ductile iron with internal coating	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Loss of coating or lining integrity; loss of material or cracking (for cementitious coatings/linings)	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-416	3.3.1-138	A
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-414	3.3.1-139	A
						VII.C1.A-415	3.3.1-140	A
		Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-51	3.3.1-072	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 3

Table 3.3.2-5 Auxiliary Systems - Circulating Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	A
			(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-209b	3.3.1-004	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.C1.AP-221b	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 3

Table 3.3.2-5 Plant-Specific Notes:

1. Internal coating: coal tar epoxy.
2. Internal lining: carbon fiber reinforced polymer.
3. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.
4. Reduction of heat transfer is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for components with only a pressure boundary function.
5. Material is aluminum-bronze (ASTM B171 Alloy 614) with less than 8% aluminum.
6. The Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program is used instead of the Open-Cycle Cooling Water System (B2.1.11) program to manage recurring internal corrosion for internally-coated steel heat exchangers.
7. Internal and external environments are such that the external surface condition is representative of the internal surface condition.
8. Cited GALL item VII.I.A-405a includes "cracking" aging effect that is only applicable for copper alloy (>15% Zn or >8% Al). Cracking is not an applicable aging effect for steel with internal lining components.
9. The Open-Cycle Cooling Water System (B2.1.11) program will manage aging of the external surfaces of buried cementitious piping.

During the original 40 years of operation, anticipated loading cycles for the Containment liner were as follows:

- Operating pressure variations from 9.5 psia to 14.7 psia were expected to occur not more than 100 times since personnel access is permitted under subatmospheric conditions.
- Temperature variations from 70°F to 105°F, resulting from seasonal swings and plant shutdowns, were expected to occur not more than 400 times.
- The design earthquake was expected to produce tremors to the extent of not more than 8 to 10 cycles and the hypothetical earthquake not more than 4 to 5 cycles.

TLAA Evaluation:

For the initial and subsequent periods of extended operation, the design cycles and anticipated cycles were extrapolated from the original design to the values shown in Table 4.6.1-1. (Reference 4.8-64).

Table 4.6.1-1 Containment Liner Load Cycles

	Design Cycles		Anticipated Cycles	
	60 years	80 years	60 years	80 years
Operating Pressure	1,500	1,500 / ~~2,000~~ (Note 1)	150	200
Operating Temperature	6,000	8,000	600	800
Design Earthquake (OBE)	30	40	12 to 15	16 to 20

Note:

1. Even if the existing accrued transient cycles are doubled to project them to 80 years of operation, there is sufficient margin in the design cycles to retain 1500 as the number of cycles used to evaluate the components for the subsequent period of extended operation (80 years).

The six conditions in ASME Code, Section III, Subsection N-415.1 were evaluated using the design cycles shown in Table 4.6.1-1 to determine the need for a detailed fatigue analysis. Effects of the Appendix J, Type A pressure tests were included in the evaluation. Each of the six conditions was shown to be satisfied. No detailed fatigue analysis is required for the Containment liner due to stress fluctuations caused by pressure, temperature, and design earthquake cycles during an 80-year plant operating term. The increase in the anticipated number of cycles due to the subsequent period of extended operation is acceptable.

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

A1.36 PROTECTIVE COATING MONITORING AND MAINTENANCE

The *Protective Coating Monitoring and Maintenance* program is an existing mitigative and condition monitoring program that manages loss of coating integrity of Service Level I coatings inside Containment. The program maintains and monitors the aging of Service Level 1 coatings consistent with RG 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants". The program consists of guidance for selection, application, inspection, and maintenance of protective coatings.

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

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

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

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

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

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

A3.7 OTHER PLANT-SPECIFIC TIME-LIMITED AGING ANALYSES

A3.7.1 Crane Load Cycle Limits

The design standard number of full-capacity lifts far exceeds the number expected of each machine for a 80-year life, even with a significant number of unforeseen lifts. The lifting machine designs therefore remain valid for the period of extended operation. These TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

A3.7.2 Reactor Coolant Pump Flywheel Fatigue Crack Growth Analysis

Fatigue crack initiation and growth in reactor coolant pump (RCP) flywheels was evaluated for the subsequent period of extended operation and documented in PWROG-17011-NP, "Update for Subsequent License Renewal: WCAP-14535A, "Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination," and WCAP-15666-A, "Extension of Reactor Coolant Pump Motor Flywheel Examination," Revision 0," which confirms that the analysis of WCAP-14535A and WCAP-15666-A remains appropriate. The fatigue crack growth calculations assumed 6000 cycles of RCP start/stop for 80 years of plant life which bounds the projected cycle count of 1158. The RCP fatigue analysis remains valid for the subsequent period of extended operation and the TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

A3.7.3 Leak-Before-Break

10 CFR 50 General Design Criterion 4 allows use of leak-before-break technology for excluding from the design basis the dynamic effects of postulated ruptures in primary coolant loop piping in PWRs. WCAP-15550-NP, Revision 2, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Surry Units 1 and 2 Nuclear Power Plants for the Subsequent License Renewal Program (80 Years) Leak-Before-Break Evaluation," demonstrated compliance with leak-before-break (LBB) technology for the reactor coolant system piping for an 80-year plant life based on a plant specific analysis that showed all LBB conditions and margins are satisfied. It is therefore concluded that dynamic effects of reactor coolant system primary loop pipe breaks need not be considered in the structural design basis. The LBB analysis has been projected to the end of the subsequent period of extended operation and the TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
11	*Open-Cycle Cooling Water* program	The *Open-Cycle Cooling Water* program is an existing preventive, mitigative, condition monitoring, and performance monitoring program that will be enhanced as follows: 1. Selected fiberglass reinforced plastic (FRP) piping in the service water system will be replaced with a more degradation resistant material such as copper-nickel (Cu-Ni) prior to entering the subsequent period of extended operation. FRP piping associated with the Units 1 and 2 charging pump cooling water subsystems, service water rotating strainers, and the control room chillers may be replaced as part of a time-phased program. 2. Modifications necessary to provide new chemical injection site upstream of the service water rotating strainers will be completed prior to entering the subsequent period of extended operation. 3. The internal lining of 24 inch and larger service water inlet piping with carbon fiber reinforced polymer, with the exception of the recirculation spray heat exchanger piping downstream of the inlet motor-operated valves, will be completed prior to entering the subsequent period of extended operation. 4. ~~Procedures will be revised to remove reference to the carbon steel piping that was replaced and will include the replacement material.~~(Completed - Change Notice 1) 5. Procedures will be revised to provide additional guidance for identifying and evaluating applicable concrete aging effects such as loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; and cracking due to chemical reaction, or corrosion of reinforcement. 6. Procedures will be revised to require personnel who perform inspections and evaluation of concrete components to be qualified consistent with the qualifications identified in the Structures Monitoring program (B2.1.34) that are consistent with the requirements of ACI 349.3R. 7. Procedures will be revised to periodically inspect for evidence of concrete aging in accessible internal surfaces of the concrete circulating water lines. The program will require that evaluation of inspection results includes consideration of the acceptability of inaccessible buried surfaces when conditions exist in accessible surfaces that could indicate the presence of, or result in, degradation to inaccessible buried surfaces. One hundred percent of the accessible circulating water line internal surfaces will be inspected in a ten year period. (Added - Set 1 RAIs) 8. Procedures will be revised to require trending of charging pump lube oil cooler and emergency service water pump engine heat exchanger inspection results by Engineering. 9. Procedures will be revised to require trending of wall thickness measurements. The frequency and number of wall thickness measurements will be based on trending results. 10. Procedures will be revised to include verification that predicted wall thicknesses at the next scheduled inspection will be greater than the minimum wall thicknesses. 11. Procedures will be revised to include criteria for the extent and rate of on-going degradation that will prompt additional corrective actions. 12. Procedures will be revised to identify acceptance criteria for visual inspection of concrete piping and components such as the absence of cracking and loss of material, provided that minor cracking and loss of material in concrete may be acceptable where there is no evidence of leakage, exposed rebar or reinforcing "hoop" bands or rust staining from such reinforcing elements.	B2.1.11	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
11	*Open-Cycle Cooling Water* program	13. Procedures will be revised to ensure that for ongoing degradation mechanisms (e.g., MIC), the frequency and extent of wall thickness inspections at susceptible locations are increased commensurate with the significance of the degradation. 14. Procedures will be revised to ensure that when measured parameters do not meet the acceptance criteria, additional inspections are performed, when the cause of the aging effect is not corrected by repair or replacement for components with the same material and environment combination. The number of inspections will be determined by the Corrective Action Program, but no fewer than five additional inspections will be performed for each inspection that did not meet the acceptance criteria, or 20% of the applicable material, environment, and aging effect combination inspected, whichever is less. The additional inspections will include inspections at both Unit 1 and Unit 2 with the same material, environment, and aging effect combination.	B2.1.11	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
20	*One-Time Inspection* program	The *One-Time Inspection* program is a new condition monitoring program consisting of a one-time inspection of selected components to verify: (a) the system-wide effectiveness of an AMP that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the subsequent period of extended operation; (b) the insignificance of an aging effect; and (c) that long-term loss of material will not cause a loss of intended function for steel components exposed to environments that do not include corrosion inhibitors as a preventive action. The One-Time Inspection program will perform a magnetic particle test inspection of the continuous circumferential transition cone closure weld on each steam generator (~~minimum 25%~~essentially 100% examination coverage of each weld) prior to the subsequent period of extended operation.(Revised - Set 1 RAIs) Industry and plant-specific operating experience will be evaluated in the development of this program.	B2.1.20	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
27	*Buried and Underground Piping and Tanks* program	The *Buried and Underground Piping and Tanks* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to establish an upper limit of -1200mV for pipe-to-soil potential measurements of coated pipes so as to preclude potential damage to coatings. 2. ~~Procedures will be revised to include visual inspection requirements and acceptance criteria for:~~(Completed - Change Notice 2) a. ~~Absence of cracking in fiberglass reinforced plastic components and evaluation of blisters, gouges, or wear~~ b. ~~Minor cracking and loss of material in concrete or cementitious material provided there is no evidence of leakage exposed or rust staining from rebar or reinforcing "hoop" bands~~ 3. Procedures will be revised to obtain pipe-to-soil potential measurements for piping in the scope of SLR during the next soil survey within 10 years prior to entering the subsequent period of operation. (Added - Set 1 RAIs) 4. Procedures will be revised to require uncoated buried stainless steel tubing segments in the fuel oil system be inspected prior to the subsequent period of extended operation. After inspection, each uncoated stainless steel segment will be coated consistent with Table 1 of NACE SP0169-2007, "Standard Recommended Practice, Cathodic Protection of Prestressed Concrete Cylinder Pipelines." (Added - Set 1 RAIs) 5. Procedures will be revised to specify that cathodic protection surveys use the -850mV polarized potential, ~~-~~instant off criterion specified in NACE SP0169-2007 for steel piping acceptance criteria unless a suitable alternative polarization criteria can be demonstrated. Alternatives include the -100mV polarization criteria, -750mV criterion (soil resistivity is less than 100,000 ohm-cm), -650mV criterion (soil resistivity is greater than 100,000 ohm-cm), or verification of less than 1 mpy loss of material rate. ~~Alternatives will be demonstrated to be effective through use of buried coupons, electrical resistance probes, or placement of reference cells in the immediate vicinity of the piping being measured.~~ The external loss of material rate is verified: • Every year when verifying the effectiveness of the cathodic protection system by measuring the loss of material rate. • Every 2 years when using the 100 mV minimum polarization. • Every 5 years when using the -750 or -650 criteria associated with higher resistivity soils. The soil resistivity is verified every 5 years. As an alternative to verifying the effectiveness of the cathodic protection system every five years, soil resistivity testing is conducted annually during a period of time when the soil resistivity would be expected to be at its lowest value (e.g., maximum rainfall periods). Upon completion of ten annual consecutive soil samples, soil resistivity testing can be extended to every five years if the results of the soil sample tests consistently have verified that the resistivity did not fall outside of the range being credited (e.g., for the -750 mV relative to a CSE, instant off criterion, measured soil resistivity values were greater than 10,000 ohm-cm).	B2.1.27	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
27	*Buried and Underground Piping and Tanks* program	When using the electrical resistance corrosion rate probes: a. The individual determining the installation of the probes and method of use will be qualified to NACE CP4, "Cathodic Protection Specialist" or similar b. The impact of significant site features and local soil conditions will be factored into placement of the probes and use of the data (Revised - Change Notice 2 and Set 1 RAIs)	B2.1.27	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
28	*Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program	The *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to require ~~additional~~baseline inspections (100% of accessible coatings/linings) of the following tanks, piping, and miscellaneous components within the scope of subsequent license renewal and inspection ~~frequencies will be modified, as necessary, to ensure consistency with NUREG-2191~~ intervals will not exceed those specified in NUREG-2191, Table XI.M42-1, "Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers." (Revised - Change Notice 2 and Set 1 RAIs) • Circulating water system waterbox air separating tanks • Condensate polishing outlet piping (short segment; entire length is inspected) • Vacuum priming tanks • Vacuum priming seal water separator tanks • Auxiliary steam drain receiver tank • Water treatment piping (short segment; entire length is inspected) • Flash evaporator demineralizer isolation valve • Brominator mixing tank • Pressurizer relief tanks 2. Programs will be revised to consistently reference coating aging mechanisms and add definitions for rusting, wear/erosion, and physical damage. 3. Procedures will be revised to require alignment of the internal coating/lining inspection criteria with the inspection criteria and aging mechanisms specified in the Coatings Condition Assessment Program. 4. Procedures will be revised to require inspections of cementitious coatings/linings and include aging mechanisms associated with cementitious coatings/linings described as cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation. 5. Procedures will be revised to require cementitious coatings/linings inspectors to have a minimum of five years of experience inspecting or testing concrete structures or cementitious coatings/linings or a degree in the civil/structural discipline and a minimum of one year of experience. 6. Procedures will be revised to require opportunistic inspections of piping internally lined with concrete and include aging associated with cementitious coatings/linings described as cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation. (Added - Change Notice 2) 7. Procedures will be revised to require a pre-inspection review of the previous "two" condition assessment reports, when available, be performed, to review the results of inspections and any subsequent repair activities. 8. Procedures will be revised to require inspection results are evaluated against acceptance criteria to confirm that the components' intended functions will be maintained throughout the subsequent period of extended operation based on the projected rate and extent of degradation. Where practical, (e.g., wall thickness measurements, blister size and (frequency), degradation is projected until the next scheduled inspection. (Added - Change Notice 2)	B2.1.28	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

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

Table A4.0-1 Subsequent License Renewal Commitments

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

B2.1.11 Open-Cycle Cooling Water System

Program Description

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

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

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

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

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

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

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

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

The aging effects associated with the external surfaces of buried concrete piping in the circulating water system will be managed by the Open-Cycle Cooling Water System program (B2.1.11). The Open-Cycle Cooling Water System program (B2.1.11) will periodically inspect for evidence of concrete aging in accessible internal surfaces of the concrete circulating water lines. The Open-Cycle Cooling Water System program (B2.1.11) will require that evaluation of inspection results includes consideration of the acceptability of inaccessible buried surfaces when conditions exist in accessible surfaces that could indicate the presence of, or result in, degradation to inaccessible buried surfaces. 100% of the accessible circulating water line internal surfaces will be inspected in a ten year period. The *Buried and Underground Piping and Tanks* program (B2.1.27) will opportunistically inspect the buried concrete circulating water lines when scheduled maintenance work permits access.

NUREG-2191 Consistency

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

Exception Summary

The following program element(s) are affected:

Detection of Aging Effects (Element 4)

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

Justification for Exception:

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

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

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

Enhancements

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

Preventive Actions (Element 2)

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

2. Modifications necessary to provide new chemical injection site upstream of the service water rotating strainers will be completed prior to entering the subsequent period of extended operation.
3. The internal lining of 24 inch and larger service water inlet piping with carbon fiber reinforced polymer, with the exception of the recirculation spray heat exchanger piping downstream of the inlet motor-operated valves, will be completed prior to entering the subsequent period of extended operation.

Parameters Monitored and Inspected (Element 3)

4. (Completed Change Notice 1)
5. Procedures will be revised to provide additional guidance for identifying and evaluating applicable concrete aging effects such as loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; and cracking due to chemical reaction, or corrosion of reinforcement.

Detection of Aging Effects (Element 4)

6. Procedures will be revised to require personnel who perform inspections and evaluation of concrete components to be qualified consistent with the qualifications identified in the *Structures Monitoring* program (B2.1.34) that are consistent with the requirements of ACI 349.3R.
7. Procedures will be revised to periodically inspect for evidence of concrete aging in accessible internal surfaces of the concrete circulating water lines. The program will require that evaluation of inspection results includes consideration of the acceptability of inaccessible buried surfaces when conditions exist in accessible surfaces that could indicate the presence of, or result in, degradation to inaccessible buried surfaces. One hundred percent of the accessible circulating water line internal surfaces will be inspected in a ten year period. (Added - RAI 1)

Monitoring and Trending (Element 5)

8. Procedures will be revised to require trending of charging pump lube oil cooler and emergency service water pump engine heat exchanger inspection results by Engineering.
9. Procedures will be revised to require trending of wall thickness measurements. The frequency and number of wall thickness measurements will be based on trending results.

Acceptance Criteria (Element 6)

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

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

Corrective Actions (Element 7)

13. Procedures will be revised to ensure that for ongoing degradation mechanisms (e.g., MIC), the frequency and extent of wall thickness inspections at susceptible locations are increased commensurate with the significance of the degradation.
14. Procedures will be revised to ensure that when measured parameters do not meet the acceptance criteria, additional inspections are performed, when the cause of the aging effect is not corrected by repair or replacement for components with the same material and environment combination. The number of inspections will be determined by the Corrective Action Program, but no fewer than five additional inspections will be performed for each inspection that did not meet the acceptance criteria, or 20% of the applicable material, environment, and aging effect combination inspected, whichever is less. The additional inspections will include inspections at both Unit 1 and Unit 2 with the same material, environment, and aging effect combination.

Operating Experience Summary

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

1. In September 2001, a through wall leak was identified in an eight inch carbon steel control room chiller service water supply line. A through wall leak in similar piping occurred again in September 2005. In May 2006, volumetric inspections measurements identified a location in an eight inch carbon steel control room chiller service water supply line that was less than the minimum allowable wall thickness. A design change was implemented, which replaced the eight inch carbon steel piping with copper-nickel piping.
2. Between August 2007 and July 2009, biofouling of the control room chillers Y-strainers and rotating strainers occurred on multiple occasions. The initial cause was thought to be insufficient backwash flow to the rotating strainers during periods of elevated service water temperatures with one control room chiller operating. Procedure changes were implemented to start an additional pump and backwash the rotating strainers when differential pressure

reaches one psid. Further clogging of the Y-strainers resulted in compensatory actions being established. These measures included increased monitoring of control room chiller and service water operating parameters when service water temperature was greater than 80°F, weekly flushing of control room chiller service water lines, and securing the chiller and cleaning the chiller suction strainers when pump suction pressure approached the minimum required net positive suction head.

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

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

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

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

6. In October 2013, during surface preparation and weld inspections, a through wall leak was observed in the 42 inch service water piping adjacent to the motor-operated valve supplying service water to the component cooling water heat exchangers from the '1B' condenser water box tunnel. The cause of pipe wall thinning was determined to be non-application of the pipe

internal coating. Historically, the motor-operated valve exhibited seat leakage since original installation. In an effort to control leakage, a blank and a hose were used to divert the leakage. As a result, the piping at the blank was unable to be properly coated. Over time, the lack of coating resulted in significant wall loss. Corrective actions included replacement of the valve with a design which would minimize valve leakage, weld repairs to the piping, and internal coating of the piping. A post-weld surface examination and system pressure test were performed satisfactorily.

7. In November 2013, three through wall leaks were identified in the 42 inch piping upstream of the motor-operated valve supplying service water to the component cooling water heat exchangers from the '1D' condenser water box tunnel. The leaks were identified following sand blasting of the piping in preparation for application of internal coating. Weld repairs were performed to correct the deficiencies. A surface examination and system pressure test were performed satisfactorily subsequent to the repairs.
8. Between September 2015 and September 2016, five leaks occurred in the service water system due to cracking of fiberglass piping. The leaks were either repaired or new piping segments installed in accordance with the work order process. The fiberglass piping in the service water system may be replaced with corrosion resistant material such as copper-nickel as part of a time-phased program.
9. In December 2015, an effectiveness review of the Service Water System Inspections Activity (UFSAR Section 18.2.17) was performed. The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. No gaps were identified by the effectiveness review.
10. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMA was conducted to confirm the following:
    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.
11. In September 2017, as part of oversight activities, of the Service Water Inspections Activity (UFSAR Section 18.2.17) it was noted that commitments for the low level intake screenwell (LLIS) and emergency service water pump suction end bell cleaning/inspections were not being performed and documented consistent with the original License Renewal commitment.

The License Renewal commitments for the LLIS cleaning and pump inspections were originally incorporated into the procedure that dewatered the LLIS. The recent license renewal cleaning/inspections were performed by divers using a recurring work activity without dewatering the LLIS. A corrective action was initiated for engineering and outage planning to resolve the inconsistency. It was determined that the cleaning and inspection commitments were satisfactorily completed without dewatering the LLIS. Update of the maintenance strategy and associated documents to allow performance of the license renewal commitments with or without dewatering the LLIS is in progress.

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

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

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

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

Recurring Internal Corrosion (RIC)

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

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

Flow Blockage:

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

Loss of Material in Uncoated Steel Piping:

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

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

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

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

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

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

Conclusion

The continued implementation of the *Open-Cycle Cooling Water System* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the subsequent period of extended operation.

B2.1.20 One-Time Inspection

Program Description

The *One-Time Inspection* program is a new condition monitoring program that will manage loss of material, cracking, and reduction of heat transfer of components containing reactor coolant, treated borated water, secondary water, fuel oil, or lubricating oil environments.

The One-Time Inspection program will conduct one-time inspections of susceptible locations to verify the effectiveness of the *Water Chemistry* program (B2.1.2), the *Fuel Oil Chemistry* program (B2.1.18), and *Lubricating Oil Analysis* program (B2.1.26). For steel components exposed to environments that do not include corrosion inhibitors, the *One-Time Inspection* program will verify that long-term loss of material will not result in a loss of intended function by performing wall thickness measurements on a representative sample of components in each environment.

The program will identify inspection locations that are isolated from the flow stream, that are stagnant, or have low flow for extended periods and are susceptible to the gradual accumulation or concentration of agents that promote certain aging effects. A representative sample size of 20% of the population (up to a maximum of 25 component inspections) will be established for each material, environment, and aging effect combination and will focus on the bounding or lead components most susceptible to aging due to time in service, and severity of operating conditions. The program will verify either no unacceptable age-related degradation is occurring or trigger additional actions that will assure the intended function of affected components will be maintained during the subsequent period of extended operation. Technical justification of the methodology and sample size used for selecting components for one-time inspection will be documented in the One-Time Inspection Sample Basis Document to be developed.

This program will not be used for components with known age-related degradation mechanisms, or when the environment in the subsequent period of extended operation is not expected to be equivalent to that in the prior operating period. Periodic inspections will be conducted in those cases.

If any inspections do not meet the acceptance criteria, additional inspections will be conducted, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2.

Where an aging effect identified during an inspection does not meet acceptance criteria or projected results of the inspections of a material, environment, and aging effect combination do not meet the above acceptance criteria, a periodic inspection program is developed for the specific material, environment, and aging effect combination. The periodic inspection program is implemented at all of the units on site with same combination(s) of material, environment, and aging effect.

The elements of the *One-Time Inspection* program will include: (a) determination of sample size for the components to be inspected based on an assessment of material, environment, aging effects, and operating experience; (b) identification of the inspection locations in the system or component based on the potential for the aging effect to occur; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (d) evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could jeopardize an intended function before the end of the subsequent period of extended operation. The monitoring methods will be effective in detecting the applicable aging effects and the frequency of monitoring will be adequate to prevent significant age-related degradation.

Inspections and tests will be performed by personnel qualified in accordance with procedures and programs to perform the specified task. ASME Code components and non-ASME Code components will be inspected using procedures consistent with the ASME Code.

Consistent with further evaluation 3.1.2.2.2(2) the *One-Time Inspection* program (B2.1.20) will perform a magnetic particle test inspection of susceptible locations of the continuous circumferential transition cone closure weld on each steam generator (~~minimum 25%~~essentially 100% examination coverage of each weld) prior to the subsequent period of extended operation.

The *One-Time Inspection* program will be implemented, and inspections will begin ten years before the subsequent period of extended operation. Inspections will be completed at least six months prior to the subsequent period of extended operation, or no later than the last refueling outage prior to the subsequent period of extended operation.

NUREG-2191 Consistency

The *One-Time Inspection* program is a new program that, when implemented, will be consistent with NUREG-2191, Section XI.M32, One-Time Inspection.

Exception Summary

None

Enhancements

None

Operating Experience Summary

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

1. In May 2012, minor pitting was observed in the lower quadrant of a carbon steel pipe in the condensate system on either side of the section that was removed to correct an abnormal alignment. The other attributes were considered acceptable. An engineering evaluation determined that the minor pitting did not indicate significant degradation of the piping that would present an integrity concern for license renewal. No further action was recommended.
2. In May 2015, a visual inspection was performed on the internal surfaces of the feedwater system to fulfill a license renewal commitment regarding the work control process. A feedwater system valve was removed to allow inspection of the valve internal surfaces and adjacent tubing. No age-related degradation was noted.

The above examples of operating experience provide objective evidence that the *One-Time Inspection* program will include activities to perform visual inspections to identify loss of material, cracking and reduction of heat transfer for components containing reactor coolant, treated borated water, secondary water, fuel oil, or lubricating oil environments within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *One-Time Inspection* program will be evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements will be provided for locations where aging effects are found. The program will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the implementation of the *One-Time Inspection* program will effectively manage aging prior to a loss of intended function. Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The implementation of the *One-Time Inspection* program will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.27 Buried and Underground Piping and Tanks

Program Description

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

The buried carbon steel piping of the fuel oil system for emergency electrical power system is the only buried piping that is protected by an active CP system. Monthly periodic inspections confirm CP system availability and annual CP surveys are conducted to assess the effectiveness of the CP system. The program uses the -850 mV relative to CSE (copper/copper sulfate reference electrode), instant off criterion specified in NACE SP0169 for acceptance criteria for steel piping and tanks and determination of cathodic protection system effectiveness in performing cathodic protection surveys. The program includes an upper limit of -1200 mV on cathodic protection pipe-to-soil potential measurements of coated pipes to preclude potential damage to coatings. For steel components, where the acceptance criteria for the effectiveness of the cathodic protection is other than -850 mV instant off, loss of material rates are measured.

The balance of piping and tanks within the scope of subsequent license renewal are not provided with CP. Based on soil sampling and testing, it has been determined that installation and operation of CP is not necessary. Soil sampling and testing is performed during each excavation and a station-wide soil survey is also performed once in each 10-year period to confirm that the soil environment of components within the scope of license renewal is not corrosive for the installed material types. Soil sampling and testing is consistent with EPRI Report 3002005294, "Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants."

External inspections of buried components within the scope of subsequent license renewal will occur opportunistically when they are excavated for any reason.

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

As an alternative to performing visual inspections of the buried fire protection system components, monitoring the activity of the jockey pump is performed by the *Fire Water System* program (B2.1.16). The water-based fire protection system is normally maintained at required operating pressure and is monitored such that a loss of system pressure is detected and corrective action initiated.

The aging effects associated with the external surfaces of buried concrete piping in the circulating water system will be managed by the *Open-Cycle Cooling Water System* program (B2.1.11). The *Open-Cycle Cooling Water System* program (B2.1.11) will periodically inspect for evidence of concrete aging in accessible internal surfaces of the concrete circulating water lines. The *Open-Cycle Cooling Water System* program (B2.1.11) will require that evaluation of inspection results includes consideration of the acceptability of inaccessible buried surfaces when conditions exist in accessible surfaces that could indicate the presence of, or result in, degradation to inaccessible buried surfaces. 100% of the accessible circulating water line internal surfaces will be inspected in a ten year period. The *Buried and Underground Piping and Tanks* program will opportunistically inspect the buried concrete circulating water lines when scheduled maintenance work permits access.

The *Selective Leaching* program (B2.1.21) is applied in addition to this program to manage selective leaching for applicable materials in soil environments.

NUREG-2191 Consistency

The *Buried and Underground Piping and Tanks* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M41, Buried and Underground Piping and Tanks.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements:

Preventive Actions (Element 2)

1. Procedures will be revised to establish an upper limit of -1200mV for pipe-to-soil potential measurements of coated pipes so as to preclude potential damage to coatings.

2. (Completed Change Notice 2)

Parameters Monitored or Inspected (Element 3)

3. Procedures will be revised to obtain pipe-to-soil potential measurements for piping in the scope of SLR during the next soil survey within 10 years prior to entering the subsequent period of operation. (Added - RAI 1)

Detection of Aging Effects (Element 4)

4. Procedures will be revised to require uncoated buried stainless steel tubing segments in the fuel oil system be inspected prior to the subsequent period of extended operation. After inspection, each uncoated stainless steel segment will be coated consistent with Table 1 of NACE SP0169-2007, "Standard Recommended Practice, Cathodic Protection of Prestressed Concrete Cylinder Pipelines." (Added - RAI 1)

Acceptance Criteria (Element 6)

5. Procedures will be revised to specify that cathodic protection surveys use the -850mV polarized potential, instant off criterion specified in NACE SP0169-2007 for steel piping acceptance criteria unless a suitable alternative polarization criteria can be demonstrated. Alternatives will include the -100mV polarization criteria, -750mV criterion (soil resistivity is less than 100,000 ohm-cm), -650mV criterion (soil resistivity is greater than 100,000 ohm-cm), or verification of less than 1 mpy loss of material rate. ~~Alternatives will be demonstrated to be effective through verification of soil resistivity every five years, use of buried coupons, electrical resistance probes, or placement of reference cells in the immediate vicinity of the piping being measured.~~

   The external loss of material rate is verified:

   - Every year when verifying the effectiveness of the cathodic protection system by measuring the loss of material rate.
   - Every 2 years when using the 100 mV minimum polarization.
   - Every 5 years when using the -750 or -650 criteria associated with higher resistivity soils. The soil resistivity is verified every 5 years.

   As an alternative to verifying the effectiveness of the cathodic protection system every five years, soil resistivity testing is conducted annually during a period of time when the soil resistivity would be expected to be at its lowest value (e.g., maximum rainfall periods). Upon completion of ten annual consecutive soil samples, soil resistivity testing can be extended to every five years if the results of the soil sample tests consistently have verified that the resistivity did not fall outside of the range being credited (e.g., for the -750 mV relative to a CSE, instant off criterion, measured soil resistivity values were greater than 10,000 ohm-cm).

When using the electrical resistance corrosion rate probes:

a. The individual determining the installation of the probes and method of use will be qualified to NACE CP4, "Cathodic Protection Specialist" or similar

b. The impact of significant site features and local soil conditions will be factored into placement of the probes and use of the data (Revised - Change Notice 2 and RAI 1)

Operating Experience Summary

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

1. In June 1994, leakage was identified in buried, carbon steel, emergency diesel generator (EDG) fuel oil lines. The leak was discovered through external visual inspection, internal boroscope inspection, and pressure drop air testing, and considered to be due to internal pitting corrosion. The 1½ inch schedule 80 carbon steel piping system was replaced with 2½ inch schedule 160 carbon steel lines in 1995. Excavation, fill placement, compaction, and testing of the soil were done in accordance with design specifications. The bedding material for the fuel oil lines is a select granular fill consisting of clean well graded sand. The coating material provided is a synthetic elastomeric tape wrap. A passive cathodic protection system was installed in 1995 to protect the buried fuel oil piping from corrosion. This passive system became degraded as the sacrificial anodes were increasingly being drained off to station grounds.

   In May 2015, an impressed current cathodic protection system was installed and placed in service to replace the passive cathodic protection system on the buried, carbon steel, EDG fuel oil lines. One of the two new rectifier units was in a degraded condition from August 2015 through February 2016, until it was restored to operation by corrective maintenance. The NACE annual inspection completed in April 2016 concluded that the system was providing adequate cathodic protection consistent with NACE criteria. Monthly inspections confirm rectifier operation.

2. In May 2004, portions of the Unit 2 auxiliary feedwater system experienced leakage in the buried carbon steel recirculation piping. The primary cause of the leak was pitting corrosion due to poorly applied coating. As a corrective action, the Unit 1 and Unit 2 AFW recirculation system piping is no longer buried and was rerouted through the safeguards building basement. The extent of condition assessment portion of the root cause evaluation noted the following:
    - The corresponding auxiliary feedwater recirculation line on Unit 1 had been discovered to be leaking and was subsequently bypassed and abandoned as part of a design change,
    - Stainless steel liquid waste piping in excellent condition,
    - Carbon steel chilled water piping with wrap intact and no indication of corrosion,
    - Carbon steel auxiliary feedwater piping with wrap in good condition and no indication of corrosion, and
    - Leaking fuel oil pipe with indications of localized pitting that was replaced and re-routed.
3. In June 2010, while removing coating from the Unit 2 condensate makeup buried carbon steel piping, pitting was identified on several areas of the pipe where the coating had been removed. The pitting was seen at three locations and was characterized as shallow. The as-found condition of the pipe was within code requirements and determined to be fit for service. Following inspection the coating was restored.
4. In July 2012, excavation revealed leakage from a buried Unit 2 ten inch stainless steel condensate supply line. There appeared to be an approximate three to four inch circumferential crack in the line that had started along the outside diameter of the pipe. The crack was determined to be caused by transgranular stress corrosion cracking due to mechanical damage by excavation equipment. The replacement pipe is not buried and has been rerouted through the turbine building.
5. In June 2016, a Dominion Energy fleet self-assessment was performed on the Underground Piping and Tank Integrity (UPTI) Program to ensure the program is supporting the goal of providing long term reliability of buried and underground piping and tanks; to ensure consistency with NEI 09-14, Guideline for the Management of Underground Piping and Tank Integrity, and NSIAC requirements; and ensure the program meets industry best practices. Implementation of the UPTI Program was reviewed to confirm performance of inspections, effectiveness of scheduling and tracking, and program optimization based on inspection results.

   This self-assessment identified one performance deficiency in that the 2015 UPTI Life Cycle Management Plan (LCMP) was issued by engineering transmittal without being approved at Plant Health Steering Committee. The 2016 UPTI LCMP was approved by Plant Health Steering Committee.

A strength was noted in that the inspections required by the UPTI LCMP are being scheduled, tracked, and performed as expected; and the results are being used appropriately to determine the next inspection. The UPTI team reviews operating experience during fleet calls and incorporates the experience into the program and inspections as appropriate.

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

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

7. In May 2017, during the as-found coating inspection on Unit 2 buried carbon steel condensate makeup piping, coating was missing on approximately 270 degrees of the pipe circumference from the center of the excavated area into the soil on the east side. Coating on the bottom was remaining. There was no visible leakage from this condensate makeup line piping segment. Ultrasonic testing of the piping segment demonstrated that the minimum wall thickness requirement was met or exceeded at each location tested. The protective coatings were restored.

8. In November 2017, as part of oversight review activities, the Buried Piping and Valve Inspection Activities (UFSAR Section 18.1.1) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

9. In January 2018, an aging management program effectiveness review was performed of the initial license renewal Buried Piping and Valve Inspection Activities (UFSAR Section 18.1.1). Information from the summary of that effectiveness review is provided below:

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

A living Life Cycle Management Plan (LCMP) that identifies inspection plans at the next five year interval is maintained based on piping wall thickness calculations, risk ranking and internal/industry operating experience. In 2004, leakage from a buried auxiliary feedwater pipe and in 2012 leakage from a buried condensate pipe resulted in design changes to reroute the piping through non-buried environments. Observed coating degradations during recent inspections resulted in coating repairs and pipe wall thickness evaluations to anticipate rates of change and confirm fitness for service. Quarterly reviews by the fleet UPTI program owners review industry and plant operating experience, including corrective actions, to identify adjustments to the program. Recent fleet operating experience from North Anna Power Station for a service water to auxiliary feedwater pipe resulted in accelerated inspection schedules for similar carbon steel piping at SPS.

In 2014, based on industry feedback, the EDG fuel oil sacrificial anode cathodic protection (CP) system was replaced with an impressed current system. Recent program reviews identified required updates to the maintenance procedures for the impressed CP system. In June 2017, as part of an Industry Material Review Visit, no adverse findings were noted for the UPTI program. Recent industry research and development is reviewed and incorporated into the program as appropriate. New soil survey studies consistent with EPRI 3002005294, "Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants," will identify any areas of soil corrosivity.

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

Conclusion

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

B2.1.28 Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

Program Description

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

Periodic visual inspections are conducted for each coating/lining material and environment combinations of the internal surfaces of in-scope piping and components where loss of coating or lining integrity could impact the components or downstream component's intended function(s). Inspection intervals will not exceed those specified in NUREG-2191, Table XI.M42-1, "Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers."

For tanks, heat exchangers and piping, all accessible surfaces are inspected. ~~The training and qualification of individuals involved in coating/lining inspections of non-cementitious coatings/linings are conducted~~If a baseline inspection has not been previously established, baseline coating/lining inspections will occur in the 10-year period prior to the subsequent period of extended operation. Subsequent inspection intervals are established by a coating specialist qualified in accordance with ASTM International Standards endorsed in RG 1.54, Revision 2, "Service Level I, II and III Protective Coatings Applied to Nuclear Power Plants," including guidance from the staff associated with a particular standard. For cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces. Peeling and delamination is not acceptable. Blisters are evaluated by a coatings specialist. Blisters are limited to a few intact small blisters that are completely surrounded by sound material and with the size and frequency not increasing between inspections. Minor cracks in cementitious coatings are acceptable provided there is no evidence of debonding. Other degraded conditions are evaluated by a coatings specialist. For coated/lined surfaces determined to not meet the acceptance criteria, the coating can be removed or physical testing is performed, where physically possible (i.e., sufficient room to conduct testing), in conjunction with repair or replacement of the coating/lining.

NUREG-2191 Consistency

The *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks.

Exception Summary

The following program element(s) are affected:

Detection of Aging Effects (Element 4).

1. Every four or six years, NUREG-2191 recommends either an inspection of a representative sample of 73 one foot axial length circumferential segments of piping or 50% of the total length of each coating/lining material and environment combination inspected, whichever is less at each unit. For two-unit sites, 55 one foot axial length sections of piping (nineteen if manufacturer recommendations and industry consensus documents were complied with during installation) are inspected per unit. An exception is taken to the inspection sample size, inspection, and re-inspection frequency.

Justification for Exception

For each unit, existing piping inspections are performed on 25% of the circulating water system (large bore piping) and service water system internal coatings every eighteen months, thereby inspecting 100% of the circulating water system and service water system piping every six years.

The existing coating on circulating water and service water piping approached the end of its expected service life and has been marginally successful in protecting the steel pipe from the corrosive effects of the brackish cooling water system. The coating has experienced localized failures exposing the pipe wall to brackish water resulting in corrosion of the exposed pipe material. The circulating water and service water piping is being repaired using a carbon fiber reinforced polymer (CFRP) lining to restore the piping pressure boundary and provide a corrosion-resistant barrier on piping internal surfaces. The CFRP relining is expected to be complete in future refueling outages.

For piping with CFRP lining, the inspection interval will be extended to twelve years if:

a. Identical coating/lining material is installed with the same installation requirements in redundant trains with the same operating conditions and at least one of the trains is inspected every six years, and

b. The coating/lining is not in a location subject to erosion that could result in damage to the coating/lining.

The determination to extend the inspection interval will be based on operating experience and inspection results.

2. ~~If a baseline inspection has not been previously established, NUREG-2191 recommends a baseline coating/lining inspection occur in the 10-year period prior to the subsequent period of~~

~~extended operation, Subsequent inspections are based on an evaluation of the effect of a coating/lining failure on the in-scope component's intended function, potential problems identified during prior inspections, and known service life history. An exception is taken to performance of baseline inspections during each inspection interval.~~

~~Justification for Exception~~

~~Baseline inspections are not required because 100 percent of all accessible internal surfaces are inspected.~~(Exception 2 Deleted - RAI 1)

3. NUREG-2191 indicates that periodic visual examinations of a sample of piping internally lined with concrete be performed to verify degradation leading to loss of material or downstream effects such as reduction in flow and pressure. Opportunistic inspections of concrete lined fire protection system main loop piping will be performed. An exception is taken to perform periodic inspections.

Justification for Exception

Concrete lined cast iron fire protection system main loop piping is buried. Inspection of this piping is highly intrusive and would require excavation and implementation of a complex temporary modification to maintain a functional fire protection header. Management of the effects of aging for the fire protection system is described in AMP XI.M27, "Fire Water System." In accordance with the Fire Water System program (B2.1.16), the following tests and inspections will be performed:

- Fire protection system underground loop and main header flow test will be conducted at least once every five years. During the flow test, system hydraulic characteristics will be measured and evaluated for indication of internal piping degradation or flow obstructions. The flow test will measure system hydraulic resistance as a means of evaluating the internal piping conditions. Monitoring system piping flow characteristics ensures that signs of internal piping degradation from significant corrosion, sediment buildup or fouling will be detected in a timely manner.
- Underground supply piping is flushed through each of the outdoor fire hydrants annually. Full flow of clean, clear water is confirmed during flushing of annual hydrant flushes.
- Wet pipe sprinkler main drain flow tests and inspector test flushes will be performed to assure adequate water supply and proper system performance. Main drain testing will be performed for wet pipe sprinkler systems with alarm control valves to monitor and trend system pressure during flow conditions and identify degraded water supply conditions should they occur.
- The motor and diesel driven fire pumps are flow tested at least every 5 years to assure flow and pressure requirements are met.

Together, these tests provide reasonable assurance that flow blockage would be detected just as effectively as if internal inspections were being periodically conducted on a portion of the piping consistent with NUREG-2191, AMP XI.M42, Table XI.M42-1. In addition, the fire water system is maintained at required operating pressure. Daily monitoring of the head and pressure in the hydro-pneumatic tank is performed. Alarm circuits monitor the system pressure, and low pressure is annunciated in the main control room via the motor driven and diesel driven fire pump start logic. A loss or decrease in system pressure would be noted and corrective actions initiated. This continuous monitoring is an effective means to detect potential through-wall flaws in the piping and piping components.

In August 2014, while conducting a fire hose station valve test, an underground fire main leak was suspected to have occurred. The suspected leak location was excavated and a circumferential break was noted in the pipe. The failed section of pipe was removed from the flanged end and submitted to the corporate materials lab for examination. Overall, the pipe section appeared to be in good condition. Visually, the pipe wall was sound, showing no signs of any extensive corrosion from the outside. Along the inner diameter, the cement lining had fractured away in the areas where the pipe was cut but the underlying metal was in excellent condition. In those areas outside the cuts, near the flange where the lining was still in place, cement lining was in good condition. The examination concluded that it is possible that a fabrication defect was present in this pipe. Away from the fracture, the overall condition of the pipe was good. No signs of any significant corrosion were seen along the outside or inside of the pipe. The heaviest corrosion noted in the form of pitting was along the outside of the pipe near the leak location.

The NRC approved a NUREG-2191 exception based on very similar justification as documented in the Safety Evaluation Report Related to the License Renewal of Fermi 2, Docket No. 50-341, dated July 2016 (ADAMS Accession No. ML16190A241).

Enhancements

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

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

1. Procedures will be revised to require ~~additional~~baseline inspections (100% of accessible coatings/linings) of the following tanks, piping, and miscellaneous components within the scope of subsequent license renewal and inspection ~~frequencies will be modified, as necessary, to ensure consistency with NUREG-2191~~intervals will not exceed those specified in NUREG-2191, Table XI.M42-1, Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers:
    - Circulating water system waterbox air separating tanks
    - Condensate polishing outlet piping (short segment; entire length is inspected)

- Vacuum priming tanks
- Vacuum priming seal water separator tanks
- Auxiliary steam drain receiver tank
- Water treatment piping (short segment; entire length is inspected)
- Flash evaporator demineralizer isolation valve
- Brominator mixing tank
- Pressurizer relief tanks

Parameters Monitored/Inspected (Element 3)

2. Programs will be revised to consistently reference coating aging mechanisms and add definitions for rusting, wear/erosion, and physical damage.
3. Procedures will be revised to require alignment of the internal coating/lining inspection criteria with the inspection criteria and aging mechanisms specified in the Coatings Condition Assessment Program.
4. Procedures will be revised to require inspections of cementitious coatings/linings and include aging mechanisms associated with cementitious coatings/linings described as cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation.

Detection of Aging Effects (Element 4)

5. Procedures will be revised to require cementitious coatings/linings inspectors to have a minimum of five years of experience inspecting or testing concrete structures or cementitious coatings/linings or a degree in the civil/structural discipline and a minimum of one year of experience.
6. Procedures will be revised to require opportunistic inspections of piping internally lined with concrete and include aging associated with cementitious coatings/linings described as cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation.

Monitoring and Trending (Element 5)

7. Procedures will be revised to require a pre-inspection review of the previous "two" condition assessment reports, when available, be performed, to review the results of inspections and any subsequent repair activities.
8. Procedures will be revised to require inspection results be evaluated against acceptance criteria to confirm that the components' intended functions will be maintained throughout the subsequent period of extended operation based on the projected rate and extent of

degradation. Where practical, (e.g., wall thickness measurements, blister size and (frequency), degradation will be projected until the next scheduled inspection.

Acceptance Criteria (Element 6)

9. Procedures will be revised to:
    a. Specify there are no indications of peeling or delamination.
    b. Require inspection of cementitious coatings/linings. Minor cracking and spalling is acceptable provided there is no evidence that the coating/lining is debonding from the base material.
    c. Require, as applicable wall thickness measurements, projected to the next inspection, meet design minimum wall requirements.

Corrective Action (Element 7)

10. Procedures will be revised to permit the "removal" of coatings/linings that do not meet acceptance criteria, with the required evaluation and documentation.
11. Procedures will be revised to include as an alternative to repair, rework, or removal, internal coatings/linings exhibiting indications of peeling and delamination. The component may be returned to service if:
    a. Physical testing is conducted to ensure that the remaining coating is tightly bonded to the base metal,
    b. the 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 3 sample points adjacent to the defective area,
    d. an evaluation is conducted of the potential impact on the system, including degraded performance of downstream components due to flow blockage and loss of material or cracking of the coated component, and
    e. follow-up visual inspections of the degraded coating are conducted within two years from detection of the degraded condition, with a re-inspection within an additional two years, or until the degraded coating is repaired or replaced.
12. Procedures will be revised to require when a blister does not meet acceptance criteria, and it is not repaired, physical testing is conducted to ensure that the blister is completely surrounded by sound coating/lining bonded to the surface. Physical testing consists of adhesion testing using ASTM International standards endorsed in RG 1.54. Where adhesion testing is not possible due to physical constraints, another means of determining that the remaining

coating/lining is tightly bonded to the base metal is conducted such as lightly tapping the coating/lining. Acceptance of a blister to remain inservice should be based both on the potential effects of flow blockage and degradation of the base material beneath the blister.

13. Procedures will be revised to require additional inspections be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending) unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement for all components constructed of the same material and exposed to the same environment. The number of increased inspections will be determined in accordance with the Corrective Action Program. However, there are no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. When inspections are based on the percentage of piping length, an additional 5% of the total length will be inspected. The timing of the additional inspections will be based on the severity of the degradation identified and will be commensurate with the potential for loss of intended function. However, in all cases, the additional inspections will be completed within the interval in which the original inspection was conducted, or if identified in the latter half of the current inspection interval, within the next refueling outage interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections. Additional samples will be inspected for any recurring degradation to provide reasonable assurance that corrective actions appropriately address the associated causes. The additional inspections will include inspections with the same material, environment, and aging effect combination at both Unit 1 and Unit 2.

14. Physical testing is performed where physically possible (i.e., sufficient room to conduct testing) or examination is conducted to ensure that the extent of repaired or replaced coatings/linings encompasses sound coating/lining material.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In December 2008, the interior surface of the Unit 1 ECST was inspected in the filled condition. There was little evidence of corrosion, but there was minor blistering of the coating on the tank

floor. The inspection of the Unit 1 ECST showed minor blistering and little evidence of corrosion that would impact minimum wall thickness.

2. In December 2008, the interior surface of the Unit 2 ECST was inspected in the filled condition. There was little evidence of corrosion, but there was minor blistering of the coating on the tank floors. An internal inspection of the Unit 2 ECST was performed in May 2017. Small blistering and pinhole damage was identified in areas of the coating along the tank walls. Internal coating repairs are scheduled in work management.

3. In December 2008, an engineering inspection of the 'A' main control room chiller revealed condenser tube erosion, but no leaks were identified and Engineering had no operability concerns. Per Engineering recommendation, Plastocor coating was placed on the tubes of 'A' main control room chiller in June 2009, and on the tubes of 'C' main control room chiller in July 2010. In January 2010, inspection revealed that the coating on the 'C' main control room chiller condenser outlet tubes had started to degrade. Coating in the tubes started to flake, crack and bubble up. Inspections of the tubes with a borescope revealed that there were spots where the copper oxide layer was flaking off. There was no corrosion, pitting, or cracking in the tubes or tubesheet. Maintenance successfully removed the loose, flaking and cracking coating. Engineering performed Eddy Current Inspection of the condenser tubes and no tube degradation was identified. In June 2010 the condenser outlet tubes were re-coated. Subsequent inspection in January 2011 revealed that the tubes and tubesheet were free of cracking, separation, or delamination. Coating was flaking three to three and half inches inside the tubes. Coating was removed where it was flaking. Inspection in June 2011 revealed no signs of degradation, pitting or erosion. Inspection performed in January 2015 and February 2016 found the condenser tubes to be acceptable for service.

4. During the Fall 2010 refueling outage (RFO), Engineering inspected the outlet line from a Unit 1 recirculation spray cooler. The line was found to have general corrosion occurring beneath the coating at the outlet flange interface on the upper endbell of the heat exchanger. The degraded coating was removed; base metal/weld repairs and coating repairs were performed during the Unit 1 fall RFO. Ultrasonic testing examination on the outlet service water flange was performed in November 2010. Exfoliation had not extended past the raised edge of the slip-on flange. Service water piping wall loss was not evident. Follow-up inspection of the outlet line was performed and coating degradation was found at the outlet flange interface on the upper end bell of the heat exchanger. Coating and weld repair were completed in November 2010. Another follow-up inspection in January 2011 noted areas of coating delamination, including the first four to six inches of pipe downstream from a service water motor operated valve, the area around the tap for a service water flow element and the tap for a service water resistance temperature detector. The areas of pipe where the delamination of coatings occurred were blasted and recoated in January 2011. Inspection of the recirculation spray cooler and ultrasonic testing of the service water vent piping is scheduled in work management.

5. In October 2010, five through wall holes were identified in a piping elbow of the Unit 1 "B" main condenser circulating water discharge piping. The piping contained raw water, and the material of construction was epoxy-coated carbon steel. Repairs were performed on the holes, and epoxy coating reapplied in February 2011.Subsequent inspections and repairs were performed in September 2016 with epoxy coating and March 2018 with the installation of the CFRP lining.

6. In November 2010, while removing a Unit 1 service water motor operated valve from the system to replace the an adjacent service water expansion joint, it was noted that the coating on the inner diameter of the pipe flange was not intact and the weld metal in the pipe to flange connection had corroded. The service water was in direct contact with the carbon steel pipe. Base metal/weld repairs and coating repairs were performed in November 2010. The weld repairs were visually inspected for a minimum acceptable wall thickness. The visual inspections were completed satisfactorily.

7. In November 2012, during the weld inspection of a Unit 2 main condenser outlet waterbox, eight areas for repair were identified due to degradation of the epoxy coating, including two through-wall areas. The waterbox contains raw water, and the material of construction is epoxy-coated carbon steel. Repairs were performed on the holes, and epoxy coating reapplied in November 2012. This is an example of recurring internal corrosion in the circulating water system. Subsequent inspections and repairs were performed in April 2014, October 2015, and April 2017.

8. In September 2014, a materials analysis was performed on buried cement lined grey cast iron fire main piping that was fractured during flow testing of hose station valves. The fracture was

attributed to a latent material defect in the cast iron. The piping was removed and replaced with an equivalent spool piece. Based on the oxidation along the top segment of the crack, the pipe had been cracked for a long period of time. High levels of calcium deposits on the fracture (from the cement lining) indicate that the pipe was partially cracked at the top segment before factory installation of the cement liner (manufacturing process). Material analysis of the pipe determined that the microstructure consisted of graphite flakes that were approximately 75% ferrite and 25% pearlite. This resulted in a reduction in the supplied material hardness. Failure of pipe was not preventable through maintenance. The failure was caused by ground settling. During the pipe replacement it was observed that there was vertical misalignment between the replacement pipe and the existing buried pipe, which indicated that the buried side piping was exerting a large bending load at the anchor/foundation. This bending load along with the pre-existing crack and lower hardness value caused the pipe fracture. The balance of the failed pipe was found in good condition with no significant loss of cement lining material, corrosion, cracking, fouling, or reduction of pipe interior diameter.

9. In April 2015, circulating and service water Carbon Fiber Reinforced Polymer (CFRP) pipe repair was performed on the interior surface of circulating water and discharge service water piping to repair and strengthen the existing pipe systems. The service water and circulating water systems piping are constructed of carbon steel piping that was originally internally coated with a coal tar epoxy coating. Over the years of operation, the coating has experienced localized failures exposing the pipe wall to brackish water and resulting in corrosion of the exposed pipe material. Since 1990 there has been a long-term service water pipe repair project which replaced the coal tar coating with a coating system using a multi-functional epoxy coating product to improve the corrosion protection. This project was completed in July 1998. The new coating system did improve the corrosion protection; however, it still has a limited service life approximately 15 to 25 years which results in localized coating failures. This coating approached the end of its expected service life and has been only marginally successful in protecting the steel pipe from the corrosive effects of the brackish cooling water system.

   A permanent repair of the service and circulating water systems piping that restores the system pressure boundaries and provides a corrosion resistant barrier to the existing system was applied to sections of the service water and circulating water piping system. This design change addresses service water piping downstream of the component cooling heat exchangers and circulating water piping downstream of the Unit 1 condenser outlet valves. The CFRP system is used to repair any degraded piping sections. The CFRP relining began in 2015 and is expected to be complete in future refueling outages. The repair process used CFRP composite designed to take the place of the existing carbon steel pipe, and as such, becomes a pipe that is capable of meeting the original design requirements of this pipeline formed within the discharge piping. The outlet piping from the component cooling heat exchangers (CCHXs) that has been relined with CFRP is rated for full system pressure, design temperature, transient load, weight effects, and vacuum pressures combined with external ground water static pressure.

In a relief request dated December 20, 2017 the NRC staff concluded that the proposed CFRP composite system provides reasonable assurance of the buried circulating water and service water piping structural integrity and leak tightness. The NRC staff stated in correspondence to Dominion dated December 20, 2017, "The CFRP repair system alternative will remain in place for the life of the plant." The station will continue to inspect approximately 25% of the circulating water system (large bore piping) and service water system internal coatings, including repaired sections, every 18 months, thereby inspecting 100% of the circulating water system and service water system piping every six years at each unit. The NRC further concluded, that based on operating experience, there is reasonable assurance to expect the CFRP repaired pipes to perform successfully and the maintenance and inspection programs will confirm acceptable performance during future inspection intervals. CFRP relining is expected to be complete in future refueling outages.

CFRP systems have been utilized in brackish water environments for over 25 years, and it is a common environment for application. This includes exposure to harsh freeze-thaw environments in bridge and pile applications within the transportation industry, upgrade to concrete infrastructure within power generation and industrial facilities, and pipeline repair and upgrade with CFRP - these types of applications are and have been completed in brackish environments with successful performance of the CFRP system.

10. In February 2016, engineering performed a coating/welding inspection inside the Unit 1 'B' component cooling heat exchanger inlet and outlet endbells. The inspection revealed fifteen areas inside the inlet endbell and ten areas on the outlet endbell requiring coating repairs. The outlet endbell also had three areas requiring base/metal weld repairs. There were no through-wall holes discovered. The weld repairs and coating were performed in February 2016. A quality inspector visually inspected the final repaired areas and a magnetic particle examination was performed on the final weld repairs. The work was completed and inspected satisfactorily.

Recurring Internal Corrosion (RIC)

Recurring internal corrosion, including through-wall failures due to pitting and general corrosion, has occurred in the coated/lined service water system piping, plumbing system piping, main condenser waterboxes and the 96-inch circulating water discharge piping. Corrective actions such as circulating water and service water liner installation that was started in April 2015 are in progress, and additional actions are scheduled to minimize the likelihood of piping and component degradation due to pitting and general corrosion in systems monitored by the *Internal Coatings/Linings For In-Scope Piping, Piping*

Components, Heat Exchangers, and Tanks program (B2.1.28). Periodic system walkdowns in accordance with plant procedure will monitor for leakage. Additional corrective actions will be determined by the Corrective Action Program if significant loss of material is detected. Work orders have been created to replace affected portions of the plumbing system piping. Future occurrences of RIC will be documented in accordance with the Corrective Action Program. Corrective actions include:

a. Prior to the subsequent period of extended operation, the 96-inch circulating water outlet piping will be lined with CFRP. The design changes for both units are in progress, and no documented aging effects for CFRP coated sections of the 96-inch circulating water outlet piping have been identified. The CFRP design changes will be completed over the next several refueling outages. Separate design changes will install CFRP in the 96 inch circulating water inlet piping and the 24-, 30-, 36-, 42-, and 48-inch service water piping from the circulating water system to the recirculation spray and supply for the component cooling heat exchangers. For epoxy coated piping sections and main condenser channel heads that do not yet have the CFRP lining installed, inspection is performed of approximately 25% of the circulating water and service water system internal coatings each refueling cycle, thereby 100% of the circulating water and service water piping is inspected every six years. Since the initial installation of the CFRP system in April 2015, there have been no condition reports to date indicating a loss of coating integrity in CFRP lined components. The CFRP system has a 50-year service life.

   The component cooling heat exchanger channel heads are epoxy-coated carbon steel exposed to raw water (service water). Inspections are performed yearly, which allows early detection of degradation of coatings and underlying metal. Inspection of the component cooling heat exchangers (CCHXs) in January 2011 discovered coating failures. Coating repairs were performed. A multi-functional epoxy coating system was applied to the Unit 1 CCHXs starting Unit 1 RFO 2013.

b. The CFRP lining is designed to meet the existing design requirements for the lines in which it will be installed and will serve as the system pressure boundary. In contrast to the existing carbon steel pipe, CFRP is not susceptible to pitting in a raw water environment. Therefore, augmented inspections will not be necessary on piping lined with CFRP. For piping sections and heat exchanger channel heads that do not yet have the CFRP lining installed, inspection of approximately 25% of the circulating water and service water system internal coatings each refueling cycle will be performed. As a result of the inspection protocol with a 25% sample population, 100% of the circulating water and service water internal coatings is inspected every six years.

Plant operating experience has demonstrated that the yearly inspections of the component cooling heat exchanger channel heads are frequent enough to detect degradation before causing a loss of intended function.

The above examples of operating experience provide objective evidence that the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program includes activities to perform visual inspections of internal surfaces to identify deficient or degraded coatings/linings for piping, piping components, heat exchangers and tanks within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program, following enhancement, will effectively manage aging prior to loss of intended function.

Conclusion

The continued implementation of the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program, following enhancement, will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.