VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

July 17, 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.: 19-260
NRA/DEA: R3
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 2

By letter dated October 15, 2018 (Agencywide Documents Access and Management System (ADAMS 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 June 12, 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 the following Enclosures:

Enclosure 1:	Response to Requests for Additional Information - Set 2 Regarding SPS SLRA
Enclosure 2:	Proprietary Response to RAIs 4.7.3-7 and B2.1.6-2 - Set 2 Regarding SPS SLRA
Enclosure 3:	Non-proprietary Response to RAIs 4.7.3-7 and B2.1.6-2 - Set 2 Regarding SPS SLRA
Enclosure 4:	CAW-19-4899, Westinghouse Affidavit for Withholding Proprietary Information: LTR-SDA-19-052-P, dated June 10, 2019; CAW-19-4901, Westinghouse Affidavit for Withholding Proprietary Information: WCAP-18258-P, Revision 1, dated June 11, 2019 and CAW-19-4912, Westinghouse Affidavit for Withholding Proprietary Information: LTR-SDA-19-053-P dated June 27, 2019

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Enclosures 2 and 7 contain information that are being withheld from public disclosure under 10 CFR 2.390.
Upon separation from Enclosure 2 or 7, this letter is decontrolled.

Enclosure 5:	SLRA Mark-ups – Set 2 RAIs
Enclosure 6:	Supporting Documents for RAI Responses
Enclosure 7:	WCAP-18258-P, "Flaw Tolerance Evaluation for Susceptible Reactor Coolant Loop Cast Austenitic Stainless Steel Elbow Components for Surry Units 1 and 2" – Proprietary
Enclosure 8:	WCAP-18258-NP, "Flaw Tolerance Evaluation for Susceptible Reactor Coolant Loop Cast Austenitic Stainless Steel Elbow Components for Surry Units 1 and 2" – Non-proprietary

Enclosure 2, which includes the response to RAIs 4.7.3-7 and B2.1.6-2, 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 Enclosures 2 and 7 contain information proprietary to Westinghouse, they are supported by Affidavits signed by Westinghouse, the owner of the information, in Enclosure 4. The Affidavits set 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 respect to the copyright or proprietary aspects of the items listed above or the supporting Westinghouse Affidavits should reference CAW-19-4899, CAW-19-4901 or CAW-19-4912, as applicable, and should be addressed to Camille T. Zozula, 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 2. It is noted that changes to five commitments (Items #8, #11, #15, #17 and #34) 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

CRAIG D SLY
Notary Public
Commonwealth of Virginia
Reg. # 7518653
My Commission Expires December 31, 2020

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 17th day of July, 2019.

My Commission Expires: 12/31/20

Notary Public

Commitments made in this letter: None

Enclosures:

1. Response to Requests for Additional Information - Set 2 Regarding SPS SLRA
2. Proprietary Response to RAIs 4.7.3-7 and B2.1.6-2 - Set 2 Regarding SPS SLRA
3. Non-proprietary Response to RAIs 4.7.3-7 and B2.1.6-2 - Set 2 Regarding SPS SLRA
4. CAW-19-4899, Westinghouse Affidavit for Withholding Proprietary Information: LTR-SDA-19-052-P, dated June 10, 2019; CAW-19-4901, Westinghouse Affidavit for Withholding Proprietary Information: WCAP-18258-P, Revision 1, dated June 11, 2019 and CAW-19-4912, Westinghouse Affidavit for Withholding Proprietary Information: LTR-SDA-19-053-P dated June 27, 2019
5. SLRA Mark-ups – Set 2 RAIs
6. Supporting Documents for RAI Responses
7. WCAP-18258-P, "Flaw Tolerance Evaluation for Susceptible Reactor Coolant Loop Cast Austenitic Stainless Steel Elbow Components for Surry Units 1 and 2" – Proprietary
8. WCAP-18258-NP, "Flaw Tolerance Evaluation for Susceptible Reactor Coolant Loop Cast Austenitic Stainless Steel Elbow Components for Surry Units 1 and 2" – Non-proprietary

cc: (w/o Enclosures except *)

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Richmond, VA 23236

Mr. Bruce Sterling, Chief Regional Coordinator
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Suffolk, VA 23435

Mr. Jonathan Lynn, Administrator
Surry County
45 School Street
Surry, VA 23883

Enclosure 4

<u>CAW-19-4899, WESTINGHOUSE AFFIDAVIT FOR WITHHOLDING PROPRIETARY INFORMATION: LTR-SDA-19-052-P DATED JUNE 10, 2019</u>

<u>CAW-19-4901, WESTINGHOUSE AFFIDAVIT FOR WITHHOLDING PROPRIETARY INFORMATION: WCAP—18258-P, REVISION 1 DATED JUNE 11, 2019</u>

<u>CAW-19-4912, WESTINGHOUSE AFFIDAVIT FOR WITHHOLDING PROPRIETARY INFORMATION: LTR-SDA-19-053-P DATED JUNE 27, 2019</u>

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, Korey L. Hosack, 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-19-052-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

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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: 20190610

Korey L. Hosack, Manager
Product Line Regulatory Support

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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COMMONWEALTH OF PENNSYLVANIA:
COUNTY OF BUTLER:

(1) I, Korey L. Hosack, 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 WCAP-18258-P, Revision 1 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.

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AFFIDAVIT

lower case letters 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: 20190211

Korey L. Hosack, Manager
Product Line Regulatory Support

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COMMONWEALTH OF PENNSYLVANIA:
COUNTY OF BUTLER:

(1) I, Paul A. Russ, 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-19-053-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.

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AFFIDAVIT

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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: 6/27/19

Paul A. Russ, Director
Licensing and Regulatory Affairs

PROPRIETARY INFORMATION NOTICE

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Enclosure 1

RESPONSE TO REQUESTS FOR ADDITIONAL INFORMATION SET 2 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 2 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 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 2.3.1.3

Background:

The systems, structures, and components (SSCs) that are in scope and subject to an aging management review (AMR) are those that perform an intended function as described in 10 CFR 54.4.

Issue:

In Section 2.3.1.3, Reactor Coolant, of the Subsequent License Renewal Application, the applicant stated that the pressurizer spray head does not form part of the reactor coolant pressure boundary or provide structural support of reactor coolant pressure boundary components and is therefore excluded from scope. Staff finds that this statement is not sufficient to determine if the pressurizer spray head should be excluded from scope. As noted in Table 2.3-1 of NUREG-2192, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants," some

plants rely on the pressurizer spray for pressure control to achieve cold shutdown during certain fire events and, in addition, failure of the spray head should be evaluated in terms of any possible damage to surrounding safety grade components, therefore, this component should be evaluated on a plant-specific basis.

Request:

Staff requests that the applicant provide additional information to justify exclusion of the pressurizer spray head from the scope of AMR by specifically addressing the concerns as noted in Table 2.3-1 of NUREG-2192 as well as the specific criteria of 10 CFR 54.4 (a)(1) - (3).

Dominion Response:

The pressurizer spray head does not perform a license renewal intended function as defined in 10 CFR 54.4(b). Specfically, the pressurizer spray head does not form part of the reactor coolant pressure boundary and is not credited for mitigation of the accidents addressed in UFSAR Chapter 14. The pressurizer spray head does not provide structural support to reactor coolant pressure boundary components and does not have a (nonsafety-related) leakage boundary function, since it is not designed to retain water without leakage, and is entirely contained within the pressurizer. The spray head is not relied upon during fire events and is not otherwise credited for compliance with any regulated event. Therefore, the pressurizer spray head is not within the scope of subsequent license renewal. This conclusion is consistent with the disposition provided in NUREG-2192 Table 2.3-1 and as stated in Section 2.3.1.3 of the SLRA.

RAI 3.5.2.2.2.6-1 (Concrete and NST Fluence/Dose Estimates)

Background:

Dominion's Subsequent License Renewal Application (SLRA) Section 3.5.2.2.2.6, as supplemented by Change Notice 1 dated January 29, 2019 (ADAMS Accession No. ML19042A137), discusses its "Further Evaluation" of the aging effects of irradiation on the Concrete Biological Shield (CBS) Wall (or Primary Shield Wall) and the Reactor Vessel (RV) Support Steel Assembly (consisting of the Neutron Shield Tank (NST) and sliding foot assembly. The SLRA concludes that no plant-specific aging management program to manage the effects of irradiation is required. The SLRA, as supplemented, discusses evaluations in support of Dominion's estimation of projected fluence and dose to the end of the subsequent period of extended operation (SPEO) at the CBS wall and at the NST, respectively, for comparison against the applicable threshold criteria for concrete in the SRP-SLR Section 3.5.2.2.2.6, and as input to the fracture mechanics evaluation for embrittlement of the RV support steel assembly.

Issue:

The conclusions made in the SLRA with respect to the need for aging management of the concrete CBS wall, NST, and related RV support structures depends, in part, on the projected fluence/dose at the end of the SPEO. The information presented in the SLRA is not sufficient to allow the NRC staff to determine whether reasonable assurance exists that the limiting fluence/gamma dose values have been identified, with sufficient margin and conservatism to accommodate uncertainties due to the relative lack of validation for fluence analysis methodologies directly applicable to the regions of interest. Therefore, with respect to the fluence/dose values presented in the SLRA and the context stated below, the NRC staff needs additional information: 1. During the audit, the NRC staff reviewed information from calculations performed in 2018 (LTR-REA-18-88 referenced in ETE-SLR-2018-1271) to determine the fluence/gamma dose at selected locations at Surry to the end of SPEO. These values provide additional validation of the fluence/dose values cited in the SLRA and SLRA supplement for the CBS wall and NST. However, the SLRA does not provide details of this model and its results. 2. The SLRA provides information for fluence/gamma dose at the vessel side surface of the CBS wall at the limiting location for the RV traditional beltline region. This location includes attenuation of the fluence through the NST. Based on a review of relevant figures and drawings (e.g., 11448/11548-FV-7A, 11448-FM-1G), there are regions of the CBS wall above and below the NST. The fluence incident on these regions do not appear to the staff to be attenuated by the steel or water present in the NST, so even though these regions are further from the traditional RV beltline, they may experience greater fluence than the part of the CBS wall closest to the RV traditional beltline region. This is especially true for neutron fluence, since a large number of neutrons would not be moderated by the NST water to energies below the lower threshold for inclusion in the fluence estimates.

Request:

1. *Provide a brief summary of the origin, details, and validation of the model used in the calculations in LTR-REA-18-88 referenced in ETE-SLR-2018-1271, including the methodology used and relevant model characteristics, to allow the NRC staff to evaluate the adequacy of the model to compute fluence in areas beyond the traditional beltline region of the RV (i.e., the area of applicability envisioned by the NRC approved methodology in the available regulatory guidance in Regulatory Guide 1.190). In addition, provide a summary of the key limiting results for the CBS wall and the NST.*

2. *Provide an estimate for the maximum neutron fluences (E > 0.1 MeV) and gamma doses associated with the regions on the vessel side surface of the CBS*

wall above and below the NST, or a justification for why the fluence/dose in these regions is bounded by other available fluence estimates.

3. *If the limiting values of fluence/gamma dose in any portion of the CBS exceed the threshold criteria in SRP-SLR, describe how the aging effects of irradiation on concrete will be adequately managed, pursuant to 54.21(a)(3) in those areas; or, provide a summary of a structural evaluation and its results that demonstrate that the CBS wall will remain capable of performing its intended function through the end of the SPEO.*

Dominion Response:

Response to RAI 3.5.2.2.2.6-1, Request 1:

The model developed by the Electric Power Research Institute (EPRI) for assessing the concrete used a Monte Carlo n-Particle (MCNP) code method for determining the neutron fluence and gamma dose projections for the concrete biological shield (CBS) wall. The information for neutron fluence and gamma dose at the CBS wall is documented in EPRI 3002013051, "Irradiation Damage of the Concrete Biological Shield that Utilizes a Neutron Shield Tank Basis for Concrete Biological Shield Wall for Aging Management." The information included in EPRI 3002013051 is reported for 72 effective full-power years (EFPY) so that it would be generic to a three loop PWR plant.

The EPRI model was performed by using the fluence at the reactor pressure vessel (RPV) inner diameter (ID) which was attenuated to obtain the fluence on the RPV outer diameter (OD). The maximum fluence at the ID used in this evaluation was determined to be $7.71E^{19}$ n/cm^2 (E > 1.0 MeV) at 72 EFPY taken from the surveillance program calculations (WCAP-18242-NP, Revision 2, "Surry Units 1 and 2 Time-Limited Aging Analysis on Reactor Vessel Integrity for Subsequent License Renewal"). EPRI developed a simplified model using the MCNP5 code for assessing radiation transport and heat loads. The model is an infinite 2-D cylinder with a point source at the center with a typical U-235 fission spectrum. Models were run to determine neutron and gamma attenuation through the concrete.

The MCNP5 model uses ENDF/BVII.O continuous energy nuclear data at 300°K with full scattering order representation. An energy cutoff was applied below 0.01 MeV on the neutron-only simulations to reduce simulation time. Additionally, geometric weight windows were used at the concrete interface to reduce variance in the flux tallies. Sensitivity studies were performed on data temperature and water thickness inside the RPV, both of which show little variation in results. EPRI baselined their work for the CBS wall to work for H.B. Robinson performed by Oak Ridge National Laboratory and

TransWare for flux ratios of > 1.0 MeV and > 0.1 MeV, as well as comparisons of the attenuation coefficient assuming exponential attenuation through the RPV.

The Westinghouse fluence model used for the RPV integrity evaluations has been modified to project neutron fluence and gamma dose for the neutron shield tank (NST) and CBS wall. The model was modified to determine the fluence in the radial direction at the NST and the interface region between the NST and CBS wall.

The Project Topical Report issued by Stone & Webster in October of 1986 was developed with funding from Department of Energy, Westinghouse Owners Group, EPRI, and Virginia Power. Because the topical report was supported by industry, the fluence information at the time was provided by Westinghouse for the reactor vessel. Westinghouse uses a two-dimensional model for determining fluence for RPV integrity.

The updated fracture toughness analysis performed by Dominion in ETE-SLR-2018-1271 is based upon fluence projections provided by Westinghouse in support of SLR. The fluence for the RPV was projected through 68 EFPY in order to complete development of the heatup and cooldown curves, LTOP evaluation, and PTS evaluation. The details of the fluence projection are outlined in WCAP-18028-NP, Revision 1, "Extended Beltline Pressure Vessel Fluence Evaluations Applicable to Surry Units 1 & 2."

Subsequent to publication of WCAP-18028-NP, Revision 1, Westinghouse amended the fluence model in order to determine the fluence for the NST and the CBS wall.

The difference between the two Westinghouse fluence reports (one used for the 1986 Project Topical Report and the other used for SLR) is that the latest projections in WCAP-18028-NP, Revision 1 (including those for the NST and the CBS wall) account for actual fuel loading patterns used over the recent life of the plant, actual operating cycle duration, a national laboratory cross-section library, and a conservative operating life of 68 EFPY. The current Westinghouse fluence model discussed in WCAP-18028-NP, Revision 1 is Regulatory Guide (RG) 1.190 compliant. The methodology used for fluence projections of the RPV has been previously reviewed and approved by the NRC as outlined in WCAP-14040-A, Revision 4, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves."

For the Units 1 and 2 RPV transport calculations, a model similar to the [r,θ] model depicted in Figure 2-1 of WCAP-18028-NP, Revision 1 was utilized since the reactor is octant symmetric. This [r,θ] model, which has finer meshes than that in WCAP-18028-NP, Revision 1, includes the core, the reactor internals, the thermal shield – including explicit representations of the surveillance capsules at 15°, 25°, 35°

and 45° – the RPV cladding and wall, the insulation external to the RPV, water filled NST, and the CBS wall.

The core for the RPV model is modeled as a homogeneous mixture of fuel, reactor coolant system (RCS) water, cladding, etc., similar to what was done in WCAP-18028-NP, Revision 1. The core source is modeled as a volumetric source in the core region modeled in the DORT model and the details are described in WCAP-14040-A, Revision 4. The neutron fluence reported by Westinghouse for the NST vessel-side surface at 68 EFPY is calculated using the same model for the RPV region as that used for RPV integrity calculation (except that the meshing in the geometrical models used in the RPV analysis were changed and the geometrical models were extended/changed to include details of the NST and existence of the CBS wall in the CBS/NST analysis).

The Units 1 and 2 RPV fluence rate synthesis calculations using the DORT code were performed using the BUGLE-96 cross-section library with refined meshes that are compliant with Regulatory Guide 1.190. The cycle-specific input parameters were used to calculate cycle-specific neutron flux values to the end of cycle (EOC) 26 for Unit 1 and EOC 25 for Unit 2.

The key limiting results for the CBS wall are summarized in the response to RAI 3.5.2.2.2.6-1 (Request 2). The key limiting results for the NST are summarized in response to RAI 3.5.2.2.2.6-4 (Request 3).

Response to RAI 3.5.2.2.2.6-1, Request 2:

NUREG-2192, Section 3.5.2.2.2.6 identifies criteria for assessment of reduction of strength and mechanical properties of concrete due to irradiation. The assessment involves the need to project the neutron fluence and gamma dose to the concrete biological shield (CBS) wall.

The approach used for determining the neutron fluence and gamma dose was to focus on three distinct regions of the CBS wall:

- Area 1 is the region adjacent to the neutron shield tank (NST),
- Area 2 is the region immediately above the NST located below the reactor pressure vessel nozzles, and
- Area 3 is the region below the NST.

Because the dose (in the reactor pressure vessel) is highest at the midpoint of the core, Area 1 was first identified to quantify the neutron fluence and gamma dose. Area 2 is of interest because this region of the CBS wall is not shielded by the neutron shield tank. The unshielded CBS wall located above and near the top of the NST is considered to contain the bounding location because it is located closest to the centerline of the core

relative to unshielded locations. At the time the SLR application was published, the neutron fluence and gamma dose were not determined for Area 3 because more of the CBS wall is protected by the NST relative to the centerline of the core (when compared to Area 1 and Area 2) and the region below the NST is further protected from gamma dose by the presence of two inches of lead shielding which is effective for shielding of gamma dose. The axial distance between the bottom of the NST and centerline of the core is approximately 486 cm. The axial distance between the top of the NST and the centerline of the core is approximately 220 cm. Because of the proximity of the core and NST, the neutron fluence and gamma dose of the CBS wall in Area 3 is considered to be bounded by the neutron fluence and gamma dose in Areas 1 and 2. Westinghouse has recently verified that the fast neutron fluence ($E > 0.1$ MeV) in Area 3 does not exceed the fast neutron fluence limit ($E > 0.1$ MeV).

Dominion contracted Westinghouse and the Electric Power Research Institute (EPRI) to determine the neutron fluence and gamma dose at the CBS wall. Specifically, Westinghouse determined the neutron fluence and gamma dose for Areas 1, 2, and 3 while EPRI determined the neutron fluence and gamma dose for Area 1.

Neutron fluence and gamma dose information for the CBS wall included in Section 3.5.2.2.2.6 of SLR application (and restated below) is for Area 1 as reported by EPRI:

- The maximum neutron fluence at the CBS wall surface is 1.18×10^{13} n/cm^2 ($E > 0.1$ MeV). This value is substantially below the threshold value of 1.0×10^{19} n/cm^2 for $E > 0.1$ MeV.
- The estimated gamma surface dose at the CBS wall of 2.75×10^6 Gy is below the acceptability threshold of 1.0×10^8 Gy.

EPRI used a Monte Carlo method (MCNP) for determining this information. The information for neutron fluence and gamma dose at the CBS wall is documented in EPRI 3002013051, "Irradiation Damage of the Concrete Biological Shield that Utilizes a Neutron Shield Tank Basis for Concrete Biological Shield Wall for Aging Management." The information included in EPRI 3002013051 is reported for 72 EFPY so that it would be generic to a three loop PWR.

EPRI baselined their work for the CBS wall to transport analyses for H.B. Robinson performed separately by Oak Ridge National Laboratory and TransWare.

The values for neutron fluence and gamma dose for Area 1 and Area 2 of the CBS wall determined by Westinghouse were not reported in section 3.5.2.2.2.6 of the SLR application. Westinghouse determined the neutron fluence and gamma dose for Area 1 and Area 2. Values for 72 EFPY are as follows:

Unit 1		
Irradiation Time 72 EFPY	Fast Neutron Fluence (E > 0.1 MeV) at Concrete Surface (n/cm^2)	Gamma Dose [Gy] at Concrete Surface
Area 1 Behind NST	1.93E+14 (Centerline of core)	2.22E+06 (Centerline of core)
Area 2 Above NST	2.86E+18 (288 cm relative to core midplane)	2.68E+06 (282 cm relative to core midplane)

Unit 2		
Irradiation Time 72 EFPY	Fast Neutron Fluence (E > 0.1 MeV) at Concrete Surface (n/cm^2)	Gamma Dose [Gy] at Concrete Surface
Area 1 Behind NST	2.13E+14 (Centerline of core)	2.46E+06 (Centerline of core)
Area 2 Above NST	3.17E+18 (288 cm relative to core midplane)	2.97E+06 (280 cm relative to core midplane)

Westinghouse revised the fluence models used for reactor vessel integrity evaluations to project neutron fluence and gamma dose for the CBS wall. The fluence models used for the reactor vessel integrity evaluations are Regulatory Guide 1.190 compliant. They were modified to determine the fluence in the radial direction at the interface region between the NST and CBS wall. There are two models based upon DORT, a 2-D model (r-theta and r-z geometries) and a one 1-D model (r geometry) that are used in the fluence rate synthesis analysis.

Dominion has provided information to the NRC previously on the models used for reactor vessel integrity. WCAP-18028-NP, Revision 1, "Extended Beltline Pressure Vessel Fluence Evaluations Applicable to Surry Units 1 & 2," provides the fluence assessment for the reactor vessel for SLR. Also, reference WCAP-14040-A, Revision 4, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves" was previously provided to the NRC.

As noted above, the neutron fluence and gamma dose for the CBS wall will remain below the threshold levels (neutron fluence greater than 1.0×10^{19} n/cm^2 for E > 0.1

MeV and gamma dose greater than 1.0×10^8 Gy) established for when irradiation damage is projected to occur to concrete. Therefore, no additional actions or activities are needed to manage or assess the possibility of damage to the CBS wall due to irradiation during the subsequent period of extended operation.

Response to RAI 3.5.2.2.2.6-1, Request 3:

Per response to Request 2 above, the limiting values of fluence/gamma dose in Area 1, Area 2, and Area 3 of the CBS wall have been demonstrated to be less than threshold limits for SLR. Therefore, the CBS wall will remain capable for performing its intended function through the end of the subsequent period of extended operation and no additional actions or activities are needed to manage or assess the possibility of damage to the CBS wall due to irradiation.

RAI 3.5.2.2.2.6-2 (Operating Experience Bases)

Background:

One criterion, among others, in SRP-SLR Section 3.5.2.2.2.6 for not requiring a plant-specific program for managing aging effects of irradiation is for the applicant to demonstrate that there is no plant-specific operating experience (OE) of irradiation degradation that may impact intended function(s) of applicable materials and components. SLRA Section 3.5.2.2.2.6, as supplemented by Change Notice 1 dated January 29, 2019 (ADAMS Accession No. ML19042A137), states "no plant-specific OE [operating experience] of concrete irradiation degradation has been identified." The SLRA supplement Section 3.5.2.2.2.6, also states that "[t]here is no plant-specific or industry OE of reactor vessel support assembly irradiation degradation that would impact a license renewal intended function."

Issue:

It is not clear what actions may have formed the bases for SPS to make the above plant-specific OE statements related to irradiation degradation of CBS wall and RV steel support assemblies.

Request:

State what actions (e.g., surveillances, inspections, observations, tests), if any, were taken by SPS to provide justification for the plant-specific OE statements made above for irradiation degradation of CBSW and RV steel support assemblies.

Dominion Response:

Accessible portions of the concrete biological shield wall, the reactor vessel sliding foot supports, and the neutron shield tank are periodically inspected by one or more of the following aging management programs: *Structures Monitoring* (B2.1.34) - 5 year frequency, *ASME Section XI, Subsection IWF* (B2.1.31) - 10 year frequency, and *External Surfaces Monitoring* (B2.1.23) - each refueling outage. Results of these periodic inspections that fail to meet the applicable acceptance criteria are entered into the Corrective Action Program. A review of condition reports generated over the past ten years identified no degradation due to irradiation that would impact a license renewal intended function for the concrete biological shield wall or the reactor vessel steel support assemblies.

RAI 3.5.2.2.2.6-3 (Whether Structural Consequence Analyses Exists in CLB)

Background:

SLRA Section 3.5.2.2.2.6, as supplemented by Change Notice 1 dated January 29, 2019 (ADAMS Accession No. ML19042A137), states: The PTR fracture mechanics evaluation on the reactor vessel support steel assembly predated resolution of Generic Safety Issue 15 (GSI-15), "Radiation Effects on Reactor Pressure Vessel Supports," in 1996, as reported in NUREG-0933 which states in part: The preliminary conclusion indicated that the potential problem did not pose an immediate threat to public safety. The tentative results indicated that plant safety could be maintained despite reactor vessel support structures (RVSS) radiation damage. In order to encompass the uncertainties in the various analyses and provide an overall conservative assessment, several structural analyses conducted demonstrated the following: 1. Postulating that one of the four RPV supports was broken in a typical PWR, the remaining supports would carry the reactor vessel and the load even under safe-shutdown earthquake (SSE) seismic loads; 2. If all supports were assumed to be totally removed (i.e., broken), the short span of piping between the vessel and the shield wall would support the load of the vessel.

Issue:

It is not clear if supporting plant-specific structural consequence analyses, that postulate failure of one or more RV support assemblies, like those cited above from NUREG-0933, exists in the current licensing basis (CLB) for SPS Units 1 and 2.

Request:

State if plant-specific structural consequence analyses, postulating failure of one or more RPV support assemblies, exists in the CLB of SPS Units 1 and 2. If they do exist,

describe in sufficient technical detail the consequence analyses performed and its results.

Dominion Response:

A plant specific structural consequence analyses, postulating failure of one or more RPV support assemblies, does not exist in the CLB of SPS Units 1 and 2.

RAI 3.5.2.2.2.6-4 (Apparent Discrepancy of Certain Fluence Values cited in SLRA)

Background:

The criteria in SRP-SLR Section 3.5.2.2.2.6 requires a plant-specific program for managing aging effects of irradiation in concrete if the estimated (calculated) fluence levels or irradiation dose received by any portion of the concrete from neutron (fluence cutoff energy E > 0.1 MeV) or gamma radiation exceeds the respective threshold level stated therein during the subsequent period of extended operation, or if there is plant-specific operating experience (OE) of irradiation degradation that may impact intended functions. SLRA Section 3.5.2.2.2.6, as supplemented by Change Notice 1 dated January 29, 2019 (ADAMS Accession No. ML19042A137), states on page 4 of 6 of Enclosure 2: "The maximum neutron fluence at the CBS wall surface of 1.18 x 10^{13} n/cm^2 (E > 1.0 MeV)" (emphasis added). Further, the SLRA supplement Section 3.5.2.2.2.6, under sub-title "Irradiation of the RV Support Steel Assembly," of Enclosure 2 states that "[t]he PTR [Project Topical Report] was conservatively estimated for 100 years of plant operation (76.8 EFPY [effective full power years]) that yields a fast neutron fluence (E > 1 MeV) of 9.5 x 10^{19} n/cm^2 at the inside surface of the RV and a fast neutron fluence (E > 1 MeV) of 5.0 x 10^{19} n/cm^2 at the outside surface of the RV." Additionally, Enclosure 2 of the SLRA supplement states: "The projected EFPY for SPS SLR is 68 EFPY which yields a fast neutron fluence (E > 1.0 MeV) of 3.42 x 10^{18} n/cm^2 at the inside surface of the NST."

Issue:

1. *The estimated neutron fluence level on the CBS wall is cited in the SLRA in terms of cutoff energy E > 1.0 MeV, whereas the neutron fluence acceptance threshold in the SRP-SLR Section 3.5.2.2.2.6 is in terms of cutoff energy E > 0.1 MeV; for appropriate comparison, they need to be stated based on the same cutoff energy as the threshold criteria in the SRP-SLR.*
2. *The staff audited the Project Topical Report (PTR) 2178-1525314-B4 "Unit No. 1 Surry Power Station – Life Extension Evaluation of the Reactor Vessel Support," dated October 10, 1986, and noted that the fast neutron fluence (E > 1.0 MeV) at*

the outside surface of the RV, used for the evaluation for 100 calendar years of operation (76.8 EFPY) is 5.0×10^{18} n/cm^2. This fluence value is inconsistent with that of 5.0×10^{19} n/cm^2 cited in the SLRA.

3. *The staff audited ETE-SLR-2018-1271, "Assessment of Radiation Effects on Reactor Vessel Supports for SPS Units 1 & 2," Revision 0, and noted that in its Table 3 the reported fast neutron fluence (E > 1.0 MeV) at the inside vessel side surface of the NST is 3.82×10^{18} n/cm^2 for Unit 2 at 68 EFPY. This fluence value is inconsistent with that of 3.42×10^{18} n/cm^2 cited in the SLRA.*

Request:

1. *Provide the maximum calculated neutron fluence values for the CBS wall for SPS Units 1 and 2 based on the cutoff energy for concrete damage as defined in SRP-SLR Section 3.5.2.2.2.6 (i.e., E > 0.1 MeV).*
2. *Clarify the inconsistency between the fast neutron fluence (E > 1 MeV) at the outside surface of the RV, cited in the SLRA with that used in the PTR for 100 calendar years of operation (76.8 EFPY), and provide the correct value to the end of the SPEO.*
3. *Clarify the inconsistency between the fast neutron fluence (E > 1 MeV) at the inside (vessel side) surface of the NST cited in the SLRA and that reported in ETE-SLR-2018-1271 for 68 EFPY. State which reactor Unit experiences the bounding fluence and provide the bounding fluence value.*

Dominion Response:

Response to RAI 3.5.2.2.2.6-4, Request 1:

Dominion concurs that, for appropriate comparison, neutron fluence values need to be stated based on the same cutoff energy as the threshold criteria in the SRP-SLR. The maximum neutron fluence at the CBS wall surface was inadvertently provided as 1.18×10^{13} /ncm^2 (E > 1.0 Mev) instead of 1.18×10^{13} /ncm^2 (E > 0.1 Mev) in the first bullet in Enclosure 2, page 4 of 6 of Dominion's Change Notice 1 letter, dated January 29, 2019 (ADAMS Accession No. ML19042A137).

As such, the first bullet should read as follows:

- The maximum neutron fluence at the CBS wall surface of 1.18×10^{13} /ncm^2 (E > 0.1 Mev). This is substantially below the threshold of 1.0×10^{19} /ncm^2 for E > 0.1 Mev.

The information in bullet one was determined by EPRI (3002013051) for the region of the CBS wall adjacent to the core. Subsequent to transmittal of Change Notice 1, the neutron fluence values for the CBS wall have been evaluated by Westinghouse for the

region adjacent to and above the NST. Westinghouse determined that the maximum neutron fluence at the CBS wall surface above the NST is 2.98×10^{18} /ncm^2 (E > 0.1 Mev) while the maximum neutron fluence at the CBS wall surface at the core midplane is 2.00×10^{14} /ncm^2 (E > 0.1 Mev) at 68 EFPY.

<u>Response to RAI 3.5.2.2.2.6-4, Request 2:</u>

A fast neutron fluence of 5.0×10^{19} /ncm^2 (E > 1.0 Mev) instead of 5.0×10^{18} /ncm^2 (E > 1.0 Mev) at the outside surface of the RPV was inadvertently provided in the second bullet in Enclosure 2, page 5 of 6 of Dominion's Change Notice 1 letter, dated January 29, 2019 (ADAMS Accession No. ML19042A137).

As such, the second bullet should read as follows:

- The PTR was conservatively estimated for 100 years of plant operation (76.8 EFPY) that yields a fast neutron fluence of 9.5×10^{19} /ncm^2 (E > 1.0 Mev) at the inside surface of the RPV and a fast neutron fluence of 5.0×10^{18} /ncm^2 (E > 1.0 Mev) at the outside surface of the RPV.

<u>Response to RAI 3.5.2.2.2.6-4, Request 3:</u>

The fracture mechanics evaluation in ETE-SLR-2018-1271 applies to SPS Unit 1. Unit 2 has a slightly higher fluence value. The scope of the fracture mechanics evaluation in ETE-SLR-2018-1271 was to re-baseline the work performed in the 1986 Project Topical Report for Unit 1 using the fluence projects for SPS Unit 1 SLR at 68 EFPY.

The maximum fast neutron fluence on the NST at the RPV-side surface for Unit 1 is 3.42×10^{18} /ncm^2 (E > 1.0 Mev) at 68 EFPY. The maximum fast neutron fluence on the NST at the RPV side surface for Unit 2 is 3.82×10^{18} /ncm^2 (E > 1.0 Mev) at 68 EFPY.

The fracture mechanics results are equally acceptable to SPS Unit 2 as demonstrated in the supplemental fracture mechanics chart that used a lower bound K_{IR} value of 26.7 ksi$\sqrt{\text{in}}$ which accounts for an infinite amount of embrittlement shift in material properties. For further details, see Figure 3 provided in the response to RAI 3.5.2.2.2.6-5, Request 3a.

<u>SLRA Changes</u>

SLRA Section 3.5.2.2.2.6, page 5 of 6, as submitted in Change Notice 1 by letter dated January 29, 2019 [ADAMS Accession No. ML19042A137], is supplemented, as shown in Enclosure 5, to correct the administrative errors described above.

<u>RAI 3.5.2.2.2.6-5</u> (Applied Stresses and Fracture Mechanics Evaluation Methodology and Results)

<u>*Background:*</u>

SLRA Change Notice 1, dated January 29, 2019 (ADAMS Accession No. ML19042A137), supplemented SLRA Section 3.5.2.2.2.6 with a new subsection entitled, "Irradiation of the Reactor Vessel Support Steel Assembly," to address the aging effect of loss of fracture toughness due to neutron irradiation embrittlement of the reactor vessel (RV) support steel materials in the neutron shield tank (NST). The applicant's evaluation is based up on the audited Project Topical Report (PTR): "Reactor Vessel Support for Unit No 1 Surry Power Station, Life Extension Evaluation of the Reactor Vessel Support, including Appendix 3, Resistance to Brittle Fracture of the Neutron Shield Tank Materials," October 10, 1986. This supplemental discussion in the SLRA states that, in this PTR evaluation, the applied stresses for the area of the NST subject to high neutron fluence were developed and compared to the critical (allowable) stresses derived from the fracture toughness evaluation. These evaluations were performed to determine the structural integrity of the Surry Unit 1 NST through the end of projected plant life or to the end of the SPEO. The applied stresses were updated in the audited report ETE-SLR-2018-1270, "Review of Loads on Neutron Shield Tank for SPS Units 1 & 2 Reactor Vessel Supports," Revision 0. The assessment of the PTR to support the supplemented SLRA is discussed in audited report ETE-SLR-2018-1271, "Assessment of Radiation Effect on Reactor Vessel Supports for SPS Units 1 & 2," Revision 0. The evaluations concluded that: a) the applied stresses calculated from the peak stress values for the associated loads of the NST were demonstrated to be below the critical (allowable) stress for a through wall flaw and a surface flaw, and b) loss of fracture toughness due to irradiation embrittlement is not an aging effect requiring management for the NST. The supplemental discussion further states that the PTR evaluation was updated for SLR in ETE-SLR-2018-1271, which validated that the original PTR evaluation is bounding for: a) the Surry Unit 2 NST, b) the applied stresses for both units through the subsequent license renewal period, and c) the 80-year projected fluence values at the inner surface of the NSTs. NUREG-1509, "Radiation Effects on Reactor Pressure Vessel Supports," provides an engineering approach, including screening criteria and technical evaluation procedures, to reassess the structural integrity of the reactor pressure vessel supports. The staff noted that the audited Attachment 2 of CM-AA-ETE-101, Technical Report CE-0087, "Condition Monitoring of Structures," Revision 7, includes up to 10 percent (minor) loss of material in the design of all SPS steel structures. The staff also noted that this report is being revised to include the NST steel structure.

Issue:

In the supplemented SLRA, the applicant provided the conclusions from the PTR and the updated evaluation that addresses the SLR period. However, the SLRA did not provide sufficient docketed details regarding the methodology used in the updated evaluation of the PTR, including derivation of the critical (allowable) and controlling applied stresses to assess the NST structural integrity during the SPEO. It is also not clear if this evaluation was performed consistent with the NRC staff guidelines in NUREG-1509. Therefore, the NRC staff needs additional information to determine the adequacy of the fracture mechanics and applied stress evaluations (subject to a 10 percent reduction in cross sectional areas as noted in Technical Report CE-0087) of the NSTs and the evaluations remain valid through the end of the SPEO.

Request:

1. *Identify and justify the specific loads (e.g., seismic, LOCA, anticipated thrust forces exerted by friction if any), loading conditions/loading combinations used or omitted as not applicable in the above postulated fracture mechanics evaluation(s) of the NST for all calculated applied stresses. State the controlling load combination, the limiting applied stresses and its location for the NSTs.*
2. *State whether all applied stresses considered for the fracture mechanics calculations of the NST were augmented to include the 10 percent reduction in steel section for loss of material due to corrosion as promulgated in Technical Report CE-0087.*
3. *In regard to the update to the PTR evaluation in report ETE-SLR-2018-1271 to support subsequent license renewal, a. Describe in detail the methodology used to perform the fracture mechanics evaluation and to calculate the corresponding critical (allowable) stresses with flaws for the NST. Include in this summary the key assumptions and inputs used, and how the evaluation accounted for the complete neutron fluence spectrum (i.e., slow and fast neutrons), added factors of safety to satisfy margins if any, alloy metals in NST steel, and other additional applicable variables. b. Provide the calculated critical (allowable) stresses for both a through-wall flaw and surface flaw.*
4. *Demonstrate that the fracture mechanics evaluation accounts for the effects of irradiation embrittlement of the weld metals used and developed heat affected zones of the parent metal in NST.*

Dominion Response:

Response to RAI 3.5.2.2.2.6-5, Request 1:

The loading conditions used in the analysis of the neutron shield tank (NST) to calculate stresses for the fracture mechanics evaluations were deadweight, design basis earthquake accelerations, and thrust forces from pipe ruptures of reactor coolant branch lines. These loading conditions are consistent with the loading conditions used in the current design basis calculations for the reactor vessel (RV) sliding supports and NST; as well as the current licensing basis, which is discussed in UFSAR Section 15.6.2.2.1. The design loads were combined consistent with the current design basis calculations and the controlling load combination are as follows:

Design Load = Deadweight + $[(\text{DBE Seismic})^2 + (\text{LOCA})^2]^{1/2}$

Notes:

1. DBE Seismic = forces due to design basis earthquake accelerations
2. LOCA = thrust forces from pipe ruptures of reactor coolant branch lines
3. The methodology for characterizing LOCA loads is discussed in UFSAR Section 14.5.3.4.1.

The limiting maximum applied tensile stress is 6.28 ksi compared to a minimum S_m (critical stress) value of 14.5 ksi. The location of the limiting maximum applied stress is the NST Shell adjacent to the RV Foot Assembly.

Response to RAI 3.5.2.2.2.6-5, Request 2:

The 10% reduction in steel section for loss of material due to corrosion was not considered when calculating the applied stresses. The *Structures Monitoring* program (B2.1.34) will be enhanced to specify that for the NST, loss of material due to corrosion, other than superficial corrosion, will be evaluated to ensure that the NST will continue to perform its intended functions, including structural support of the RV.

Response to RAI 3.5.2.2.2.6-5, Request 3a:

Dominion used the fracture mechanics evaluation included in Appendix 3 of the 1986 Project Topical Report, "Project Topical Report for Unit 1 Surry Power Station – Life Extension Evaluation of the Reactor Vessel Support, October 10, 1986. Stone & Webster Engineering Corporation. Report No. 2178-1525314-B4," to assess the impact of irradiation to the neutron shield tank (NST). Subsequent to publication of the 1986 Project Topical Report, NRC issued NUREG-1509, "Radiation Effects on Reactor Pressure Vessel Supports," May 1996, outlining a possible method for assessing the impact of irradiation for reactor vessel supports. To date, most utilities have not assessed the impact of irradiation on the reactor vessel supports because the NRC and

industry previously agreed that no additional actions where needed to manage the effects of irradiation to reactor vessel supports. This agreement is documented in the NRC SE (Safety Evaluation) report attached to WCAP-14422, "Licensing Renewal Evaluation: Aging Management for Reactor Coolant System Supports," Revision 2-A, December 2000 and reads as follows:

"Furthermore, in resolving GSI-15 concerns, Revision 3 to NUREG-0933, "Resolution of Generic Safety Issues (Formerly entitled "A Prioritization of Generic Safety Issues)," Main Report with Supplements 1-34. Issue No: 15, "Radiation Effects on Reactor Vessel Supports," concludes that:

> The preliminary conclusion indicated that the potential problem did not pose an immediate threat to public safety.... The tentative results indicated that plant safety could be maintained despite reactor vessel support structures radiation damage... In order to encompass the uncertainties in the various analyses and provide an overall conservative assessment, several structural analyses conducted demonstrated the following:
>
> 1. Postulating that one of the four RPV supports was broken in a typical PWR, the remaining supports would carry the reactor vessel and the load even under safe-shutdown earthquake seismic loads;
> 2. If all supports were assumed to be totally removed (i.e., broken), the short span of piping between the vessel and the shield wall would support the load of the vessel.
>
> The results of the analyses virtually eliminated the concern for both radiation embrittlement and significant structural damage from a postulated RPV failure.... Based on the staff's regulatory analysis, the issue was resolved with no new requirements. Consideration of a license renewal period of 20 years did not change this conclusion.
>
> Because of the foregoing, the staff considers that neutron embrittlement is not a concern for the RCS supports, and does not warrant an aging management program."

Due to the history associated with this issue, clear guidance for assessment of reactor vessel supports does not currently exist; however, in the resolution of GSI-15 (NUREG-0933, Revision 3) the NRC concluded that structural integrity of supports are maintained for long-term plant operations. NRC resolved this issue in GSI-15, NUREG-0933, Revision 3 for 60 years. However, at that time, the documentation for NRC review and approval of WCAP-14422, Revision 2-A did not mention 80 years of operations on a generic basis.

As part of initial license renewal, Dominion investigated the RV supports for 100 years in the 1986 Project Topical Report, "Project Topical Report for Unit 1 Surry Power Station – Life Extension Evaluation of the Reactor Vessel Support, October 10, 1986. Stone & Webster Engineering Corporation, Report No. 2178-1525314-B4." Nonetheless, NRC requested that Dominion assess the impact of embrittlement of the reactor vessel supports as part of subsequent license renewal. In response to this request, Dominion verified that the configuration of the Unit 1 and Unit 2 NSTs are similar, and used current licensing basis loads to validate that information in the 1986 fracture mechanics evaluation is applicable through the SLR operating lifetime. The results of this work are documented in

1. ETE-SLR-2018-1269, "Review of Shield Tank Configuration for SPS Units 1 & 2 Reactor Vessel Supports," December 6, 2018.
2. ETE-SLR-2018-1270, "Review of Loads on Neutron Shield Tank for SPS Units 1 & 2 Reactor Vessel Supports," December 13, 2018.
3. ETE-SLR-2018-1271, "Assessment of Radiation Effect on Reactor Vessel Supports for SPS Units 1 & 2," December 26, 2018.

Due to lack of guidance for assessment of the embrittlement of the reactor vessel supports, it is recognized that utilization of the methods outlined in NUREG-1509, the 1986 Project Topical Report, and ETE-SLR-2018-1271 contains a level of uncertainty. The Dominion assessment outlined in the 1986 Project Topical Report and ETE-SLR-2018-1271 uses fracture mechanics formulas (consistent with those provided in ASME Boiler & Pressure Vessel Code, 2013 Edition, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," Appendix A) to demonstrate that a postulated surface flaw and postulated through wall flaw are stable based on a lower bound fracture toughness K_{IR} curve (i.e. $K_I < K_{IR}$), and does not propagate in an unstable behavior (i.e. brittle fracture). The assessment is performed by re-arranging the stress intensity factor formulas to back calculate the critical stress corresponding to when brittle fracture would occur. The results of the fracture mechanics evaluation from ETE-SLR-2018-1271 is shown in Figure 1.

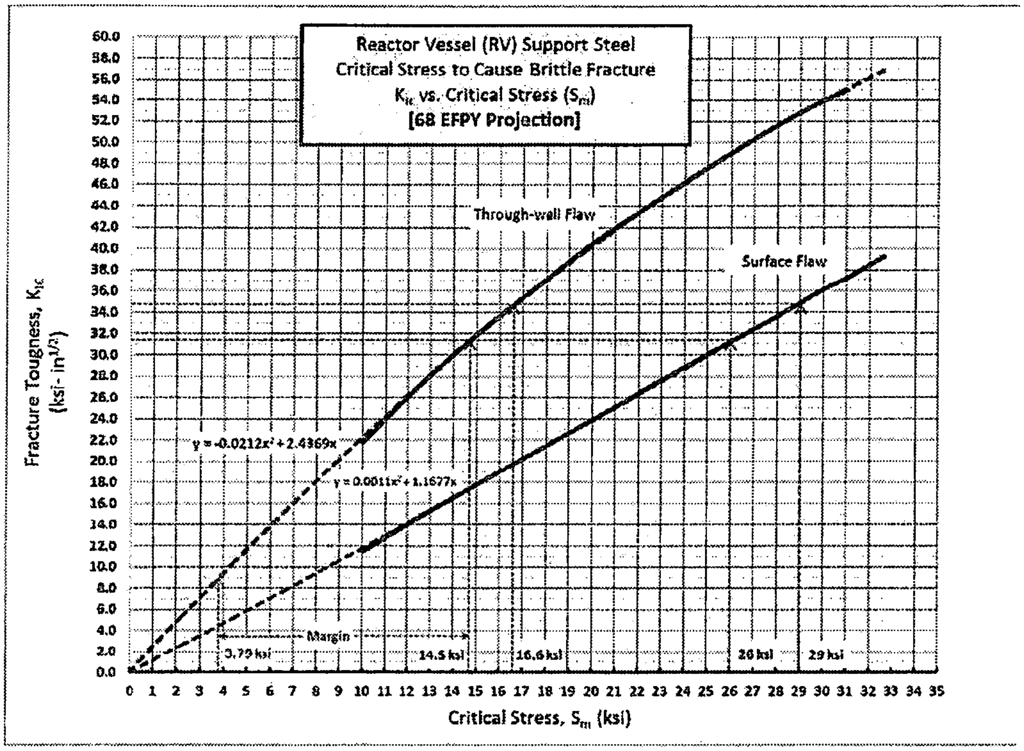

Figure 1 (Extracted from ETE-SLR-2018-1271)

During discussions with NRC it was recognized that application and quantification of ASME code margins (consistent with structural margins in Section XI, IWB-3600) or use of a bounding analysis would be helpful. In response to this recognition, Dominion has used a safety margin of √2 on K_{IR} fracture toughness based on ASME Code, Section XI, IWB-3600 (note that K_{IR} and K_{IA} from ASME Code, Section XI, Appendix A-4200 are synonymous). Moreover, as an additional conservatism, the lower bound K_{IR} value of 26.7 ksi√in from the ASME Code is used to determine the critical stress. This critical stress is back-calculated for a 1/4T postulated surface flaw and a postulated through wall flaw per the linear elastic fracture mechanics methodology as discussed in the 1986 Project Topical Report and ETE-SLR-2018-1271. If the design basis actual stresses are below the critical stresses, then the critical regions of the NST are protected against brittle fracture.

The sensitivity assessment shown below is based upon the lower bound K_{IR} value of 26.7 ksi√in which accounts for an infinite amount of embrittlement shift in material properties. In other words, the value of 26.7 ksi√in is the lowest value K_{IR} can reach when the value of T-RT_{NDT} is very low (as shown in Figure 2), assuming a very high embrittlement and a large shift in RT_{NDT} based on NUREG-1509, Figure 3-1.

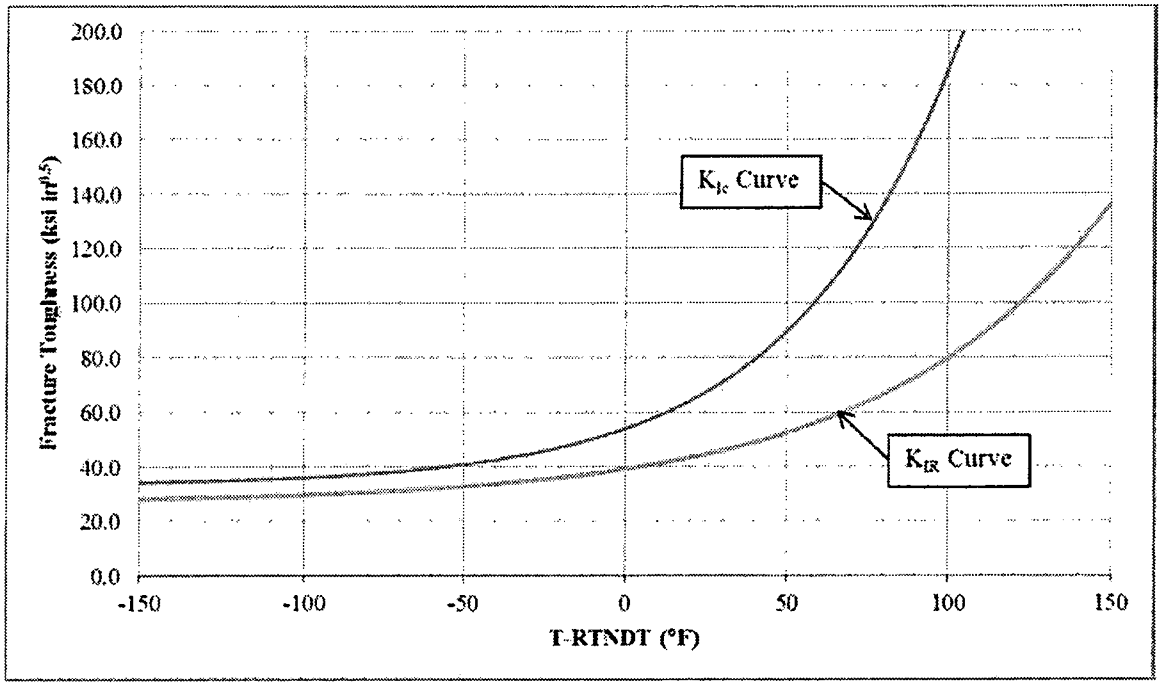

Figure 2 Fracture Toughness K_{IR} and K_{Ic}

(Same as shown in Figure A-4200-1 of ASME Code, Section XI)

Incorporating a safety margin based on IWB-3600, gives $K_{IR}/\sqrt{2}$ = 18.9 ksi$\sqrt{in}$. Based on Figure 3 below, for $K_{IR}/\sqrt{2}$ = 18.9 ksi$\sqrt{in}$, the postulated through-wall flaw has a S_m that is approximately 8 ksi, while for the surface flaw, the S_m is approximately 16 ksi. These above mentioned S_m values are larger than the applied tensile stresses from Table 1 (6.31 ksi) and from Table 2 (6.28 ksi) of ETE-SLR-2018-1271 for both the postulated through-wall flaw and the postulated 1/4T surface flaw, respectively.

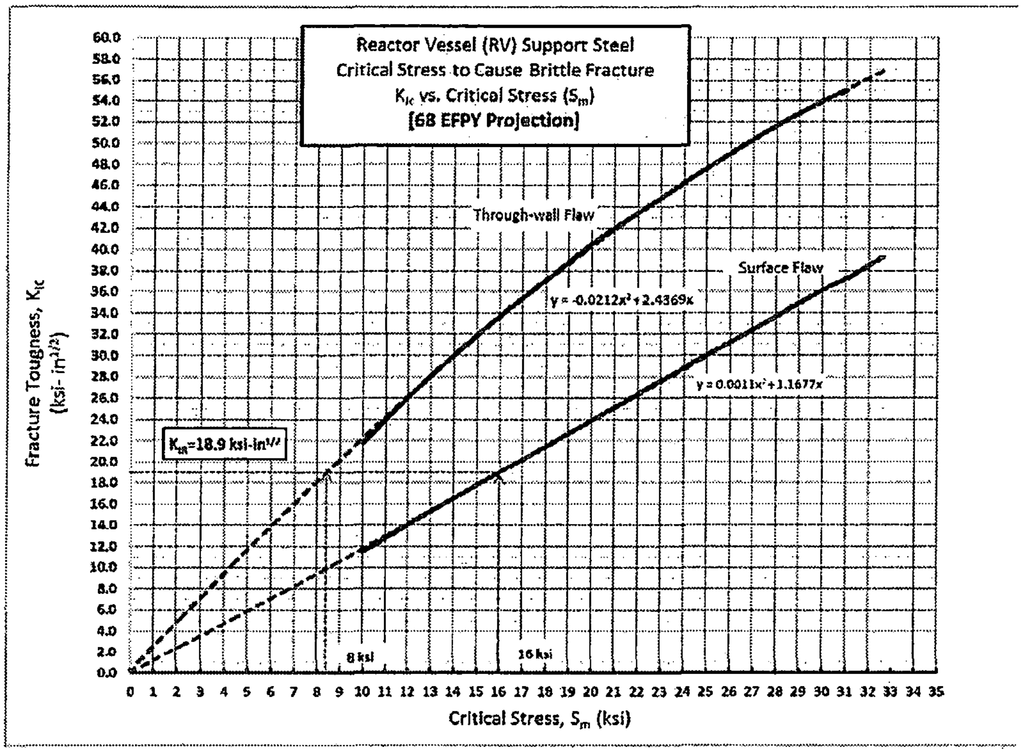

Figure 3 Sensitivity Assessment ($K_{IR}/\sqrt{2}$)

Thus, the RV supports are acceptable even if a lower bound K_{IR} of 26.7 ksi√in is considered with incorporation of safety margins from IWB-3600. Therefore, the neutron shield tank will maintain structural integrity throughout its lifetime (even past 80 years of operation, if the design basis stress stays below the critical stresses) since it is not possible to experience neutron damage in excess of that illustrated by the lower bound K_{IR} value.

Taken collectively, the results of the 1986 Project Topical Report, ETE-SLR-2018-1271, and sensitivity assessment discussed above and shown in Figures 1 through 3 affirm the NRC's previous conclusion in GSI-15 (NUREG-0933, Revision 3) that neutron embrittlement of reactor vessel supports is not a concern for the neutron shield tanks through the subsequent period of extended operation.

Response to RAI 3.5.2.2.2.6-5, Request 3b:

Per Figure 3, based upon the lower bound K_{IR} value of 18.9 ksi√in, which includes the safety margin of √2, the calculated critical (allowable) stresses for a through-wall flaw and surface flaw are approximately 8 ksi and 16 ksi, respectively. These S_m values are larger than the applied tensile stresses from Table 1 (6.31 ksi) and from Table 2

(6.28 ksi) of ETE-SLR-2018-1271 for both the postulated through-wall flaw and the postulated 1/4T surface flaw.

Response to RAI 3.5.2.2.2.6-5, Request 4:

Specification NUS-0096, "Stone & Webster Document, "Specification for Fabrication of Neutron Shield Tank for Surry Power Station," Revision 5, September 20, 1968. J. O. Nos. 11448/11548. NUS-96," specifies, "The entire shield tank shall be stress relieved except for the final weld joining the two sections of the skirt." Stone & Webster Drawing 11448-FV-7A, Issue 6, "Reactor Neutron Shield Tank Assembly – Surry Power Station, Virginia Electric and Power Company," indicates, "After welding and prior to machining, shield tank to be stress relieved at 1050°F for one hour per inch of thickness." This stress relief substantially removes residual stresses.

According to the 1986 Project Topical Report, special quality requirements imposed on the materials included:

- NDT tests for all A-516 plate over 1/2 inch thick,
- Drop weight tear tests for A-516 plate up to 1/2 inch thick,
- A grain size of six or finer for the maraging steel,
- Nonmetallic inclusion limits on the maraging steel,
- Ultrasonic testing of maraging steel forgings,
- Fracture toughness of the maraging steel per Stone & Webster Drawing 11448-FV-7D, Revision 8, "Reactor Neutron Shield Tank – Surry Power Station - Unit 1,"
- Drop weight tests of the deposited weld metal to be employed in welding the A-516 plate with an NDT of -40°F, and
- Charpy-Vee values of -40°F in the heat affected zone of welded test pieces.

The last two bullets indicate that design of the NST included weld and heat affected zone (HAZ) considerations.

HAZ material was also subject to neutron embrittlement. While a large amount of HAZ data does not exist at the conditions of interest to quantify the magnitude of shift for HAZ material there is sufficient margin in the allowable stresses associated with the fracture mechanics evaluation to accommodate uncertainty in embrittlement of the HAZ material.

However, a comprehensive study of U.S. surveillance capsule testing of HAZ 30 ft-lb transition temperature values compared with 30 ft-lb values for companion RPV plate or

forging concluded that essentially all the 30 ft-lb values of HAZ were lower (tougher) than the 30 ft-lb values of the companion plate or forging in the irradiated condition (see Troyer, G. and Erickson, M., "Empirical Analyses of Effects of the Heat Affected Zone and Post Weld Heat Treatment on Irradiation Embrittlement of Reactor Pressure Vessel Steel," Effects of Radiation on Nuclear Materials: 26th Volume, STP 1572, Mark Kirk and Enrico Lucon, Eds., pp. 163–178, ASTM International, West Conshohocken, PA, 2014.ASME Code, Section XI, Division 1, Code Case N-838, "Flaw Tolerance Evaluation of Cast Austenitic Stainless Steel Piping," Approval Date: August 3, 2015). Structural welds have many passes, which improves HAZ toughness properties relative to the base metal due to grain refinement, small regions of coarse grains, and tempering of martensite, all of which tend to increase toughness. Based on this study and the similarity of the low alloy steel plates, it is expected that the NST HAZs would behave in a similar manner.

The embrittlement of the weld metal as well as the base metal is assessed using the bounding curve in Figure 9.2 of the 1986 Project Topical Report.

The embrittlement curves in NUREG-1509 and the Remec study (Remec, I., Wang, J., and Kam, F., "HFIR Steels Embrittlement: The Possible Effect of Gamma Field Contribution," Effects of Radiation on Materials: 17th International Symposium, ASTM 1270, Eds D.S. Gelles, R.K. Nanstead, A.S. Kumar, and E.A. Little, ASTM 1996, 591) include weld metal data which is indistinguishable from the base metal.

As discussed in the above response to Request 3 of this RAI, the RPV supports are acceptable even when a lower bound K_{IR} of 26.7 ksi$\sqrt{in}$ is considered with incorporation of safety margin of $\sqrt{2}$ from IWB-3600. The use of a postulated higher embrittlement still demonstrates margin between the S_m and the actual stresses. The fracture mechanics evaluation when based on a lower bound K_{IR} of 26.7 ksi$\sqrt{in}$ incorporates the consideration of irradiation of HAZ's and welds, therefore demonstrating structural integrity of the RPV supports.

<u>SLRA Changes</u>

SLRA Section B2.1.34 and Table A4.0-1, Item 34 are supplemented, as shown in Enclosure 5 to add an Enhancement to the Structures Monitoring program as described in Request 2 above.

RAI 3.5.2.2.2.6-7 (Impact of NST Leakage)

Background:

Scoping and Screening results of mechanical systems of SLRA describes the cooling functions of the Neutron Shield Tank (NST) system. SLRA Section 2.3.1.3, "Reactor Coolant," states that "[t]he reactor coolant system includes a neutron shield tank located inside the primary shield wall around the reactor vessel," and that aging management of the neutron shield tank is addressed in the mechanical section of the application. SLRA Section 2.3.3.9, "Neutron Shield Tank Cooling," states that "[t]he neutron shield tank cooling system provides cooling for the neutron shield tank fluid which is heated by attenuation of neutron and gamma radiation in the vicinity of the reactor vessel. Heat removal is provided by the component cooling system. The neutron shield tank cooling system also removes heat from the primary shield wall." SLRA Section 3.5.2.2.2.6, "Reduction of Strength and Mechanical Properties of Concrete Due to Irradiation," identifies the heated water to be contained within the 1-1/2-inch-thick steel shell walls of the tank. Title 10 of Code of Federal Regulations (10 CFR) Part 54.4 requires that systems, structures, and components including those that assure the integrity of the reactor coolant pressure boundary remain functional during and following design-basis events and that their intended functions form the basis for including them within the scope of license renewal and subject to aging management review (AMR) such that they continue to fulfill their intended function consistent with 10 CFR 54.21(a).

Issue:

UFSAR Section 11.3, states that "[p]rimary shielding is provided to limit radiation emanating from the reactor vessel." It also states that "[t]he primary shield consists of a water-filled neutron shield tank [...which...] designed to prevent overheating and dehydration of the concrete primary shield wall and to prevent activation of the plant components within the reactor containment. In its OE audit, the staff reviewed CA238320 included in CR479576 for SPS Unit 2 and noted that the NST has been experiencing chromated water leakage of up to two and one-half gallons per day since 1989. It is not clear how the NSTs can perform their radiation and thermal shielding functions to protect the reactor primary shield wall effectively when they experience unmitigated leakage. It is also not clear what corrective actions the applicant has taken to remedy leakage such as that experienced in the Unit 2 NST or plans to take for any potential NST leakages during the SPEO. It is further not clear what AMPs and AMRs address management of relevant aging associated with NST leakage.

Request:

1. *Discuss proposed plans to maintain structural integrity of the primary shield wall (PSW) (i.e., reduce/eliminate overheating, dehydration, and radiation induced degradation of the reactor primary shield wall) when NSTs experience fluid leakage of fluid conducive to shielding of PSW.*
2. *Clarify the AMPs and AMRs that manage the impact of chromated fluid leakage from NST on external surfaces of affected components.*

Dominion Response:

Response to RAI 3.5.2.2.2.6-7, Request 1:

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

A surge tank, connected to the shield tank via surge line piping, is located approximately eleven feet above the neutron shield tank. The surge tank functions to provide an expansion/contraction volume for the neutron shield tank. Due to its orientation above the neutron shield tank, maintaining level in the surge tank ensures that the neutron shield tank is maintained full.

Surge tank level indication and alarm is provided in the main control room. The alarm functions to notify the control room operators if level in the surge tank is too high or too low.

A connection from the component cooling water system is provided on the surge line. If addition of water to the neutron shield system is required, operators can remotely open a valve to add water from the component cooling system in accordance with plant procedures.

During unit operation, a decrease in the surge tank level indication would alert the operators to leakage from the neutron shield tank. By adding water from the component cooling system, as described above, level in the surge tank would be maintained in the normal operating range. Historically, a maximum of two additions to the Unit 2 surge tank have been required annually to maintain the level within the normal operating range.

As described above, the neutron shield tank is maintained full. Maintaining the neutron shield tank full maintains the shielding for the primary shield wall. Since a loss of shielding for the primary shield wall is not expected, degradation from overheating, dehydration, or radiation is not anticipated. Therefore, there is no need or plans for

additional actions designed to reduce/eliminate overheating, dehydration, and radiation induced degradation of the primary shield wall.

Response to RAI 3.5.2.2.2.6-7, Request 2:

The Unit 2 neutron shield tank has indications of minor leakage on the underside of the tank at two penetration baseplates that cover the neutron detector tubes. Indication of the leakage appears as yellow chromate deposits originating at the baseplates, extending downward, towards the side of the neutron shield tank support skirt.

This condition is documented in the Corrective Action Program. Investigation determined that the most likely cause of the leakage is shroud weld defects which propagated through the shrouds that enclose each neutron detector tube on or before 1989.

Degradation of structural components due to neutron shield tank leakage (chromated leakage) is not expected because chromates are a very effective corrosion inhibitor. The structural steel of the neutron shield tank support skirt is in good material condition, with superficial or no rusting, and minimal or no material wastage. Chromated water and chromate deposits on the neutron shield tank support skirt are cleaned as appropriate.

As indicated by SLRA Table 3.1.2-3, reactor coolant system aging management evaluation, the *Structures Monitoring* program (B2.1.34) manages aging of the external surfaces of the neutron shield tank, including the neutron shield tank support skirt. Inspections of the external surfaces of the neutron shield tank, including the neutron shield tank support skirt, are performed on a 5-year frequency.

RAI 3.5.2.2.2.6-8 (NST Water Chemistry Sampling for Corrosion)

Background:

Scoping and Screening results of mechanical systems of SLRA Section 2.3.3.9, "Neutron Shield Tank [NST] Cooling" describes cooling of the NST fluid heated by attenuation of neutron and gamma radiation near the reactor vessel. SLRA Section B2.1.12., "Closed Treated Water Systems [CTWS]" describes activities including chemistry of the fluid used to prevent loss of material to the NST. The audited SPS procedure CH-93.400 "Closed Cooling Water Chemistry Program," further delineates the fluid chemistry of the steel NST and indicates that it is monitored every refueling outage. SPS CH-93.400 procedure also states that the NST mitigating fluid chemistry is examined for its alkalinity and contents of chlorides, chromates, and iron. The enhancement to the "detection of aging effects" program element of SLRA Section B2.1.12 AMP states that a new SPEO procedure will be developed to inspect a 20%

sample of various populations (each material, water treatment program, and aging effect combination) every 10 years. The enhancement also states that if opportunistic inspections will not fulfill the minimum number of inspections by the end of each 10-year period, the program owner will initiate work orders as necessary to request additional inspections.

Issue:

The SLRA identifies NST to be subject to corrosion mechanism and its mitigating fluid to heat and radiation. Given that the CTWS program is a sampling program, it is not clear from the SLRA how the chemistry of the NST fluid is sampled (i.e., at the NST or at other components 32 having the same material, environment, and aging effect characteristics). It is also not clear how the adverse localized environment of heat and radiation affect the chemistry of the contained fluid and if such chemistry has affected the NST internal (e.g., steel, seals, and other materials) construction.

Request:

1. *Discuss how, where (including location if sampled within NST), and at what frequency the NST fluid is sampled. If chemistry data are not directly obtained at the NST but at other sampled components discuss the relevance of such components in providing accurate data that can be used to interpret loss of material at the NST.*
2. *Discuss how the chromated fluid chemistry controls have trended over the plant life. Provide several years trending of relevant NST chemistry data to asses for loss of material OE evaluation. If chromate data has changed since the beginning of plant operation explain why and justify how so.*
3. *Discuss to what extent heat and radiation affects the NST fluid chemistry.*

Dominion Response:

Response to RAI 3.5.2.2.2.6-8, Request 1:

The neutron shield tank sampling procedure directs that sufficient water is purged from the sample line prior to drawing the sample to ensure a representative sample is obtained.

The sample line is located on the return line from the neutron shield tank coolers to the neutron shield tank. Natural circulation moves water from the top of the neutron shield tank, through piping to the coolers, and back through the return piping into the bottom of the neutron shield tank. The temperature difference between the top and bottom of the neutron shield tank water is the thermal driving force for the flow. Convective flow of approximately 4-5 gallons per minute from the neutron shield tank flows through this

piping. Since the neutron shield tank water is constantly recirculating, the samples are representative of the bulk neutron shield tank chemistry.

Water chemistry analysis of the neutron shield tank is conducted every refueling outage.

Response to RAI 3.5.2.2.2.6-8, Request 2:

Since 2001, chemistry results for both units' neutron shield tank identified the chloride concentration range between 80 and 400 ppb for Unit 1 and between 70 and 850 ppb for Unit 2, with no discernible trend. The fluoride concentration has ranged between 80 and 310 ppb for Unit 1 and between 70 and 210 ppb for Unit 2, with no discernible trend. A one-time step increase in chloride and fluoride concentrations was noted for Unit 1 and Unit 2 in 2009 and 2008, respectively. However, as indicated by the results above, chloride and fluoride concentrations remain far below the procedural limit of 10,000 ppb. A technical evaluation, performed following the Unit 2 one-time step increase, identified that contaminants introduced into the system during maintenance were the most likely source of the increase.

In 2005, the neutron shield tank plant sampling procedure was revised to specify the requirement for iron concentration analysis. Iron is sampled as a diagnostic parameter and does not have a specified operating range. Spikes in iron can be indicative of an active corrosion event. The detection limit for the analysis instrumentation is 0.13 ppm. With the exception of one sample at each unit, iron concentration has been less than 0.13 ppm for both units since 2005. The two samples (one sample at each unit) that were above 0.13 ppm were marginally above, and thus, did not warrant further investigation.

Since 2011, chromate concentration has ranged between 780 and 930 ppm for Unit 1 and between 195 and 220 ppm for Unit 2, with no discernible trend. In 2013, one outlier result of 240 ppm for Unit 1 was obtained. This result is attributed to an issue with the analysis, since subsequent samples were approximately 800 ppm. The normal operating range for chromate specified by procedure is 150 to 1000 ppm. As an additional point of reference, Unit 1 chromate concentration in 1984 was 978 ppm. No batch chemical additions have been necessary to correct chromate concentration for either unit over plant life.

Concerning the issue of chromate concentration over time, initially following tank fill, chromate concentration in the water decreased as the protective oxide film on the interior surfaces of the tank was established. Subsequent decreases in concentration were primarily due to periodic water additions from the component cooling system to make up for system leakage. However, any decrease due to makeup from the component cooling system is expected to be minimal, due to the fact that the

component cooling system is also a chromated system with the same lower concentration limit as the neutron shield system (150 ppm).

Response to RAI 3.5.2.2.2.6-8, Request 3:

Heat does not affect the neutron shield tank water chemistry because the neutron shield tank coolers function to maintain shield tank water less than 125°F during operation.

The neutron shield tank water chemistry has not been negatively affected from radiation. Sampling of neutron shield tank water is performed every refueling outage to ensure chemistry parameters remain in specification. There have been no corrective actions related to chemistry.

The oxide film formed by chromate water treatment on the tank internal surfaces serves to protect the base metal. As stated in EPRI Report 3002000590, "Chromate is a strong oxidizing agent that accelerates the oxidation of ferrous ions to ferric ions so that a thin adherent iron oxide quickly forms at the anodic surface. Metal oxides caused by this reaction become passive and are relatively inert to further oxidation or corrosion." EPRI Report 3002000590 also discusses the impact of dissolved oxygen on corrosion rates. "In inhibited CCW systems (nitrite, molybdate, nitrite/molybdate, chromate, silicate), a passive film is established, and the presence of dissolved oxygen does not appear to have a significant impact on corrosion rates."

Iron results of samples have consistently been at the minimum level of detection for the analysis instrumentation, providing an indirect indication that active corrosion in the tank is not occurring.

RAI 3.5.2.2.2.6-9 (Potential Degradation of Lubrite® Lubricant)

Background:

In its SLRA, Section 3.5.2.1.36, "Component Supports," the applicant stated that Lubrite is a material of construction used in structural support subcomponents within the containment. The applicant also stated that aging effects such as loss of mechanical function require aging management for component support subcomponents. The applicant proposed to manage the effects of aging of Lubrite® exposed to air used to lubricate the sliding foot assemblies for the reactor vessel (RV) supports with the ASME Section XI, Subsection IWF AMP. However, the applicant did not identify whether the Lubrite® at the sliding foot assemblies is susceptible to degradation when exposed to radiation. During the On-Site audit, the staff reviewed excerpts from EPRI Technical Report 3002013084, "'Structural Tools' – Long Term Operations: Subsequent License Renewal Aging Effects for Structures and Structural Components," (EPRI Report) and the Project Topical Report (PTR) for Unit No. 1 Surry Power Station, "Life Extension

Evaluation of the Reactor Vessel Support dated October 10, 1986, (Life Extension Report) and had discussions with the applicant's staff. As stated in the Life Extension Report, the applicant uses Lubrite® Type II lubricant to lubricate the bottom of the sliding block for the reactor vessel supports. The Lubrite® is described as a solid lubricant comprised of graphite and an organic binder. However, the staff has not previously accepted the full EPRI Report or the Life Extension Report for use in subsequent license renewal and has not determined the applicability of the statements in these documents to potential aging effects of Lubrite® for this application. Additionally, both documents discuss the potential for organic materials to degrade when exposed to radiation, and the need to consider this as a potential aging effect. The EPRI Report contained an excerpt that stated "...humidity, high temperature, and radiation are not significant in the aging of Lubrite." However, the EPRI Report also states that change in materials properties due to radiation is an applicable aging effect if the gamma radiation exceeds a previously defined limit. Additionally, the EPRI Report recommends that "[e]ach plant should review specific material types of manufacturer's data for detailed information" regarding gamma radiation effects. The PTR Life Extension Report states that if visual inspections under the ASME Code were implemented, they would not provide an indication of an impending lubrication failure. The PTR goes on to state that due to consequences of binding in the sliding foot assemblies and the potential for lubricant degradation, further study or monitoring for binding is recommended. The PTR Life Extension Report also states that at the time the report was written, it was unknown if radiation tests were performed on the lubricant and that "[t]he radiation stability of bonded solid lubricants, like Lubrite II, depends on the properties of the binder." Further, the Life Extension Report states that "...on-line monitoring to detect stick-slip behavior may be implemented, especially if the long-term properties of the lubricant cannot be reliably ascertained." Additionally, the PTR Life Extension Report states that it is possible to tolerate radiolytic degradation of the binder if it does not produce an adverse effect on the binder's cohesion or adhesion properties. However, the Life Extension Report does not discuss the binder's cohesion or adhesion properties for the staff to assess whether the specific binder used in the Lubrite® at Surry would be able to withstand radiolytic degradation.

Issue:

As noted in both the EPRI and the PTR Life Extension Reports, Lubrite® has the potential to degrade when exposed to radiation. Additionally, audited literature from Lubrite® Technologies as provided by the applicant states that radiation can degrade lubricants and therefore each lubricant must be designed to meet the specific conditions encountered. Because the applicant has not provided information that demonstrates the lubricant used at Surry was designed to withstand the expected radiation fluence/dose

over 80 years, it is not clear to the NRC staff that the Lubrite® used in the construction of RV sliding shoe assemblies will continue to perform its intended function throughout the SPEO, and whether its degradation will not impose additional applied stresses on the NSTs and RVs. Potential loss of lubricating ability of the Lubrite® may need to be considered in conjunction with the RAIs dealing with applied stresses for the RPV sliding shoe assemblies.

Request:

1. *Clarify which Lubrite® lubricant is used in the sliding foot assemblies for the RV supports.*

2a. *Clarify whether the organic binder is designed to sustain degradation and still ensure the lubricant can perform its intended function for the subsequent period of extended operation: a. If so, provide the technical justification as to why the binder degradation can be tolerated at Surry. The justification should account for aging effects due to radiation and fluence exposure that would be encountered by the lubricant during the SPEO (60 – 80 year span) at Surry. Discuss whether such degradation would impose additional adverse stress effects and the impact the stresses would have on the ability for the supports to perform their intended function.*

2b. *If necessary, considering any answer to request (2)(a) above, provide qualification data, and compare to site-specific conditions, for the specific lubricant used at Surry that demonstrates the lubricant will not experience significant degradation due to environmental factors such as temperature, accumulated gamma radiation dose and flux, and neutron fluence and flux that this material is projected to receive (or be exposed to) through the SPEO. Note that for any qualification data provided it should include aging effects due to both slow and fast neutrons, if applicable.*

2c. *Considering the answers to a. and/or b. above, is the depletion rate of the lubricant sufficiently low to ensure the lubricant can perform its intended function through the end of the SPEO?*

3. *If the organic binder for the lubricant contains halogens, provide a discussion on how production of acids may impact corrosion of components in contact with the lubricant and justify why it will not contribute significantly to corrosion of these components.*

4. *State whether the accumulated gamma radiation dose, and neutron fluence the lubricant is projected to receive through the SPEO will degrade the graphite component of the lubricant. Include qualification data, and compare to site-*

specific conditions, for the lubricant that demonstrates the graphite component of the lubricant will not experience significant degradation that would impact the intended function of the lubricant or provide a justification for not needing to do so.

5. *Based on operating experience data, provide confirmation that no degradation of the Lubrite® lubricant (i.e. loss of mechanical function) has been observed at Units 1 and 2 of Surry.*

Dominion Response:

Response to RAI 3.5.2.2.2.6-9, Request 1:

Lubrite Type II (Lubrite) lubricant is the type of lubricant used in the RV sliding foot assemblies. As noted in the PTR Life Extension Report, Lubrite is a solid lubricant that consists of graphite and an organic binder. The specific material constituents are not available since the use was discontinued in the early 1970's, subsequent to use in the Surry assemblies. The design of the RV sliding support assemblies selected the Lubrite material recommended by the manufacturer for service temperatures of 500°F and above, and a composition that suffers no damage due to fast neutron exposure in excess of 1.5×10^{18} n/cm^2.

Response to RAI 3.5.2.2.2.6-9, Request 2a:

The available information about the binder for Lubrite is limited; however, the binder and the graphite were reviewed during the initial license renewal effort. Based on discussions with the manufacturer, the following is a summary of that review:

> Lubrite lubricant consists of graphite and a binder. The purpose of the binder is to assist in the initial installation of the graphite lubricant and the binder permits the lubricant to be compressed into trepanned recesses in the bearing surface by an extrusion process. The binder was subsequently baked off the installed graphite lubricant, and after fabrication and baking, the Lubrite lubricant is essentially pure graphite, with some trace amounts of metallic oxides to enhance its lubricity. The graphite lubricant is known to be stable for high-temperature exposure for long periods of time with no compromise of its structural integrity or lubricating capabilities. The manufacturer confirmed that the Lubrite lubricant is intended for high-temperature application. Additionally, based on *Nuclear Engineering Handbook*, First Edition, the graphite's inherent stability with regard to exposure to irradiation has also been determined to be favorable. This reference source indicates that significant changes to the dimensional characteristics and other physical properties of graphite require very large doses of neutrons. For instance, neutron irradiation to doses of 20E20 n/cm^2 is noted to cause changes in the

length of the graphite from about -1.0% to 4.0%, depending on orientation and temperature of exposure. Other graphite physical properties appear to be similarly resistant to the effects of neutron radiation. Given that the fluence levels at the RV sliding foot assemblies projected through 80 years of plant operation are orders of magnitude less, it was concluded that this would not result in any appreciable change in length of the graphite that could lead to a loss of structural integrity or a reduction in its lubricity.

Based on recent analysis performed by Westinghouse for SLR, the fast neutron fluence (E > 1.0 MeV) projected through 80 years of plant operation at approximately the Neutron Shield Tank (NST) top elevation (i.e., location of RV sliding foot assemblies) is estimated to be less than 5×10^{17} n/cm^2. As noted in the Response to Request 1 above, the manufacturer indicated that Lubrite suffers no damage due to fast neutron exposure in excess of 1.5×10^{18} n/cm^2. Significant changes to the dimensional characteristics and other physical properties of graphite require doses of neutrons that are significantly larger than the neutron fluence projected through 80 years of plant operation.

The amount of movement associated with the RV sliding foot assemblies is relatively small as stated in WCAP-14422, "License Renewal Evaluation: Aging Management for Reactor Coolant System Supports," Revision 2-A. WCAP-14422 indicates a "reactor vessel nozzle pad moves about 3/8-in. during plant heatup." Adverse stresses resulting from potential Lubrite degradation were not included in the estimate of member stresses because of the superior material properties and the relatively low cycle application.

Response to RAI 3.5.2.2.2.6-9, Request 2b:

Based on the preceding information, it was concluded that aging effects due to degradation of Lubrite due to temperature or radiation would not be significant. However, the potential aging effect resulting from Lubrite degradation due to irradiation would be loss of mechanical function. Loss of mechanical function of the Lubrite sliding surfaces is an aging effect that is being managed by the ASME Section XI, Subsection IWF (B2.1.31) program.

Response to RAI 3.5.2.2.2.6-9, Request 2c:

No industry or plant-specific operating experience associated with depletion of Lubrite has been identified. The amount of movement during plant heatup associated with the RV sliding foot assemblies is relatively small. This coupled with the fact that the number of heatups and cooldowns the plant will experience through the subsequent period of extended operation were considered relatively insignificant; the potential depletion rate of the Lubrite associated with the RV sliding foot assemblies was concluded as not a concern.

Response to RAI 3.5.2.2.2.6-9, Request 3:

The specific constituents of the binder used with Lubrite are not available. However, the organic binder was baked off following installation as noted above. NUREG-2191 notes that corrosion is a mechanism that could result in loss of mechanical function for Lubrite sliding surfaces. The *ASME Section XI, Subsection IWF* program (B2.1.31) manages the loss of mechanical function of the Lubrite sliding surfaces associated with the RV sliding foot assemblies. The *ASME Section XI, Subsection IWF* program (B2.1.31) also manages loss of material due to general and pitting corrosion for the materials associated with the RV sliding foot assemblies.

Response to RAI 3.5.2.2.2.6-9, Request 4:

Based on recent analysis performed by Westinghouse for subsequent license renewal, the fast neutron fluence (E > 1.0 MeV) projected through 80 years of plant operation at approximately the Neutron Shield Tank top elevation (i.e., location of RV sliding foot assemblies) is estimated to be less than 5×10^{17} n/cm^2. As noted in the Response to Request 1 above, the manufacturer indicated that Lubrite suffers no damage due to fast neutron exposure in excess of 1.5×10^{18} n/cm^2. Significant changes to the dimensional characteristics and other physical properties of graphite require doses of neutrons that are significantly larger than the neutron fluence projected through 80 years of plant operation.

Response to RAI 3.5.2.2.2.6-9, Request 5:

A detailed review of SPS ASME Section XI, Subsection IWF operating experience has not identified the loss of mechanical function for the RV support sliding foot assemblies.

RAI 3.5.2.2.2.6-10 (Stress Corrosion Cracking of RV Support Sliding Foot Components)

Background:

The NRC staff audited CE-1653, "Review of Structural Adequacy of the Reactor Vessel Support Sliding Foot Assemblies – Surry Units 1 and 2" dated May 27, 2003. The report states that major components of each RV sliding foot assemblies (i.e., ball, socket plates, sliding block, stationary saddle block, and hold down plates) are fabricated from high strength maraging Vascomax ® 300 or 350 steels. The report also states that Vascomax ® 300 or 350 steels are susceptible to stress corrosion cracking (SCC) subject to environmental conditions. The GALL-SLR Report Section IX.F, "Aging Mechanisms," and its references state that for certain steels (in particular those containing Nickel) SCC is an aging effect that needs to be managed. SPS UFSAR indicates that Vascomax ® is a maraging iron-based steel alloy that includes a large

percentage of nickel as an alloy strengthening agent. In addition, the SLRA supplement by letter dated January 29, 2019 (ADAMS Accession No. ML19042A137), references Project Topical Report (PTR) 2178-1525314-B4 "Unit No. 1 Surry Power Station – Life Extension Evaluation of the Reactor Vessel Support," dated October 10, 1986, states that the components of the sliding foot assembly were coated with Heresite™ VR 514 (a phenolic coating). The NRC staff audited the PTR and noted that it states that the Heresite™ coating may not be needed to prevent stress corrosion cracking of the maraging steel components of the sliding foot assembly unless normal operating loads are exacerbated by lubrication failure. The Surry SLRA as revised, does not appear to discuss the Heresite™ coating, or whether it has applicable aging effects requiring management.

<u>Issue:</u>

The Life Extension Report discusses the use of Heresite™ VR 514 as a preventive coating to manage Vascomax ® steels susceptibility for SCC. It is not clear how the applicant would manage SCC of Vascomax ® steels used in the RV shoe assembly components, if the coating cannot provide the required adequate protection for SCC of Vascomax ® steels subject to environmental conditions, including radiation exposure, during the SPEO. The staff noted that there was no AMP or AMRs that address the susceptibility of Vascomax ® steels to SCC. It is also unclear whether the Heresite™ VR 514 coating is subject to any aging effects requiring management, and if so, whether degradation of the coating is being managed by any AMPs.

<u>Request:</u>

1. *Identify what AMP and AMRs will SPS use to manage the effects of aging due to SCC for the Vascomax ® steels used in the fabrication of the RV shoe assembly components.*
2. *State whether the Heresite™ coating(s) used, is (are) subject to any aging effects requiring management or credited for corrosion control of components that are in-scope for the SLRA.*
3. *Clarify and justify if no management of aging effects for Vascomax ® steels and/or of the Heresite™ coating(s) used in the RV shoe assembly components is required.*

Dominion Response:

Response to RAI 3.5.2.2.2.6-10, Request 1:

Vascomax was used in the fabrication of RV sliding foot assemblies; however, SCC is not an aging effect that requires management. The justification for not managing cracking due to SCC of Vascomax is provided in the response to request 3 of this RAI.

Response to RAI 3.5.2.2.2.6-10, Request 2:

The Heresite coating is not credited for corrosion control of RV sliding foot assemblies, does not have a subsequent license renewal intended function and is not within the scope of license renewal. Therefore, aging management of the Heresite coating is not required.

Response to RAI 3.5.2.2.2.6-10, Request 3:

Loss of material due to general and pitting corrosion for the Vascomax portions of the RV sliding foot assemblies is managed by the *ASME Section XI, Subsection IWF* program (B2.1.31).

The Heresite coating was used to facilitate initial installation of the sliding foot assemblies so it is does not perform a license renewal intended function. The Heresite is not credited for corrosion control of RV sliding foot assemblies; therefore, aging management is not required.

Stress corrosion cracking is a type of corrosive attack that occurs through the combined actions of stress, a corrosive environment, and a susceptible material. CE-1653 notes that Vascomax RV sliding foot assemblies are susceptible to stress corrosion cracking (SCC) subject to environmental conditions. However, CE-1653 also states that the stresses in the Vascomax sliding foot assemblies are below the threshold for SCC "...since the conditions required for crack growth - aqueous environment, high temperatures during operation, etc. are not present."

WCAP-14422, Revision 2-A "License Renewal Evaluation: Aging Management for Reactor Coolant System Supports" (Reference NRC ML010660256 and ML010660324) states that the "only steel components of the RCS supports that are potentially subject to SCC are bolts and anchors made of high-strength material."

Therefore, cracking due to SCC is not managed for the Vascomax materials used in the fabrication of RV sliding foot assemblies. However, cracking due to SCC is managed for high-strength bolts used in RV sliding foot assemblies by the *ASME Section XI, Subsection IWF* program (B2.1.31).

RAI 4.7.3-7

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

RAI 4.7.7-1

Background:

The applicant provides its time-limited evaluation of underclad cracking in SLRA Section 4.7.7, "Cracking Associated with Weld Deposited Cladding" (henceforth, referred to as the TLAA on RPV Underclad Cracking). The applicant states that the current flaw evaluation in WCAP-15338-A, which assessed postulated cladding cracks over a 60-Year licensing basis was reassessed in PWR Owners Group Report No. PWROG-17031-NP, Revision 0, to account for potential flaw growth over an 80-year licensing basis. The applicant states that the TLAA is acceptable in accordance with the criterion stated in 10 CFR 54.21(c)(1)(ii) because the analysis has been projected to the end of the subsequent period of extended operation.

Issue:

In order to demonstrate that the cycle-dependent flaw tolerance or crack growth evaluations of PWROG-17031-NP, Revision 1, do not involve a fluence dependency (as defined for the current operating term in accordance with Criterion 3 in 10 CFR 54.3a), the staff will need further demonstration that the use of a fracture toughness value of 200 ksi-√in represents a valid, conservative lower-bound fracture toughness input for the values of K_{Ia} and K_{Ic} cited in the analysis.

Request:

Please justify the use of a fracture toughness of 200 ksi-√in as a conservative, lower bound value for the values of K_{Ia} and K_{Ic} in the analysis.

Dominion Response:

Allowable Flaw Size Calculation

Surry Units 1 and 2 rely on the generic underclad cracking evaluation in PWROG-17031-NP, "Update for Subsequent License Renewal: WCAP-15338-A, 'A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants'," Revision 1, May 2018. PWROG-17031-NP and WCAP-15338-A, "A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants," Revision 0, October 2002 calculates K_{Ic} fracture toughness per ASME Section XI, Appendix A, A-4200. K_{Ia} was not used in the underclad cracking evaluation. Since there is no

prescribed upper limit in the ASME code, 200 ksi√in was conservatively used as a maximum value (or "upper shelf"), even if the calculated K_{Ic} is higher per the ASME Section XI, Appendix A, A-4200 formula. See Figure 1 for a visual demonstration of the 200 ksi√in value superimposed on the ASME Section XI, Appendix A K_{Ic} curve.

FIG. A-4200-1 LOWER BOUND K_{Ia} AND K_{Ic} TEST DATA FOR SA-533 GRADE B CLASS 1, SA-508 CLASS 2, AND SA-508 CLASS 3 STEELS

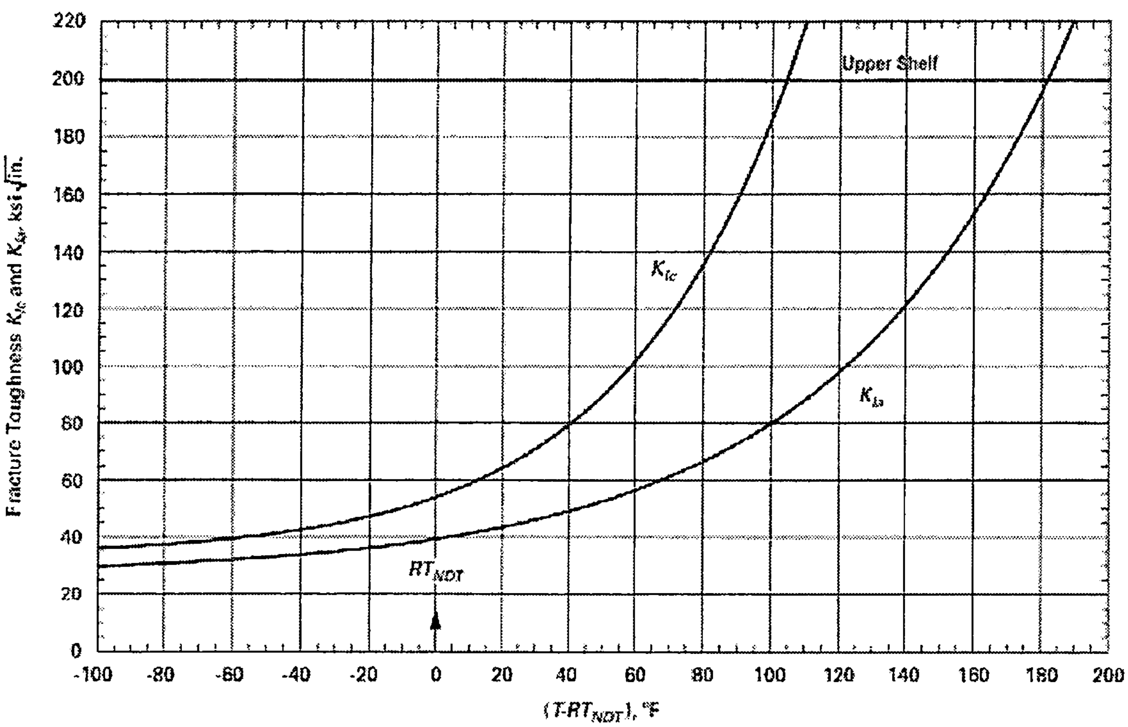

Figure 1. K_{Ic} Curve with 200 ksi√in Upper Shelf

(U.S. Customary Units)

$$K_{Ic} = 33.2 + 20.734 \exp[0.02\ (T - RT_{NDT})]$$

$$K_{Ia} = 26.8 + 12.445 \exp[0.0145\ (T - RT_{NDT})]$$

In PWROG-17031-NP, all limiting transients for normal, upset, and test conditions have high fluid temperatures, and the calculated K_{Ic} exceeds 200 ksi√in even if the 10 CFR 50.61 PTS screening criterion of 270°F is used. Therefore, K_{Ic} was limited to 200 ksi√in to maintain conservatism and be in line with industry practices. Per WCAP-18242-NP, "Surry Units 1 and 2 Time-Limited Aging Analysis on Reactor Vessel

Integrity for Subsequent License Renewal," Revision 2, July 2018, Surry Units 1 and 2 do not exceed the 270°F PTS screening criterion at 68 effective full-power years (EFPY).

For transients of emergency and faulted conditions (Level C and D transients), if $T\text{-}RT_{NDT} > 104.25$ °F, 200 ksi$\sqrt{in}$ is used; otherwise, the K_{Ic} equation per A-4200 is used.

For the Steam Generator Tube Rupture and Small Loss-of-Coolant Accident (LOCA) Level C and D transients, the calculated K_{Ic} exceeds 200 ksi$\sqrt{in}$ when using the 270°F 10 CFR 50.61 PTS screening criterion for RT_{NDT}. Surry Units 1 and 2 have performed Leak Before Break (LBB) analysis and the implementation of LBB eliminates Large LOCA.

The Surry steam line break transients were provided to the NRC in BAW-2178, Supplement 1NP-A, "Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W Owners Reactor Vessel Working Group for Levels C & D Service Loads," Revision 0, December 2018. One of these transients is the generic System Standard Design Criteria 1.3 transient. This transient starts approximately at the cold leg temperature, and then rapidly drops. As the transient continues, the temperature gradually decreases to approximately the boiling point of water at atmospheric conditions. The transient temperatures are not exclusively in the upper-shelf regime. Thus, K_{Ic} calculated per A-4200 is used to determine the critical flaw size. The critical flaw sizes for the Level C and D transients are based upon a typical Westinghouse Pressurized Water Reactor (PWR) for 60 years, as referenced in PWROG-17031-NP and described in WCAP-15338-A, Section A-1. Consistent with the information in PWROG-17031-NP, Revision 1, Section 5.6, RT_{NDT} is not expected to change significantly from 60 to 80 years as the rate of material embrittlement decreases at higher fluence levels. This "saturation" effect is evidenced by Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," Figure 1. For Surry Units 1 and 2, this effect is evidenced by the similarities between the ΔRT_{NDT} values in Section 4 of WCAP-18242-NP and the ΔRT_{NDT} values applicable to 60-year PTS evaluations.

The maximum flaw depth due to fatigue crack growth for 80 years is 0.4267 inches as shown in PWROG-17031-NP, Section 5.4. This represents a significant margin compared to the Normal/Upset/Test allowable flaw depth of 0.67 inches. As a further conservatism, underclad cracks are assumed to be surface flaws which results in a conservative K_I. The surface flaw assumption also results in a higher calculated fatigue crack growth rate as it considers a water environment.

The Level A/B allowable flaw size from PWROG-17031-NP is 0.67 inch, while the Level C/D allowable flaw size is 1.25 inch. The 60-year to 80-year reduction of K_{Ic} and the allowable flaw size for Level C/D due to a fluence increase would have to be more than 46% for the Level C/D allowable flaw size (1.25 inch) to be smaller than the Level A/B allowable flaw size (0.67 inch). This reduction is highly unlikely given the change in fluence from 60 years to 80 years for Units 1 and 2 from WCAP-18242-NP and the corresponding change in K_{Ic}. Therefore, the Level A/B allowable of 0.67 inch in the PWROG report remains bounding.

Pressurized Thermal Shock Considerations

The reactor vessel must be protected from failure in two separate regions of operation, the high temperature "ductile" region and the lower temperature "brittle" region. The allowable flaw size determination demonstrates that an underclad crack will not propagate leading to a reactor vessel failure in the ductile region. Using an RT_{NDT} of 270°F (consistent with the 10 CFR 50.61 PTS screening criterion) ensures a K_{Ic} value of 200 ksi$\sqrt{in}$ will be used to a temperature of approximately 375°F. When using a lower RT_{NDT}, 200 ksi$\sqrt{in}$ is applicable to a lower temperature. For Units 1 and 2, the limiting RT_{PTS} value (equivalent to RT_{NDT}) per WCAP-18242-NP Section 4 is 253.2°F for weld materials and 170.8°F for base metals. In the lower temperature region, where brittle failure is a concern, the plant is protected by pressure-temperature limit curves (for normal heatup and cooldown operations) and 10 CFR 50.61.

Regardless of the RT_{NDT} value utilized for the critical flaw size determination in WCAP-15338-A and PWROG-17031-NP, protecting the beltline region of a PWR Reactor Vessel (RV) from fracture during a large steam line break is ultimately ensured through compliance with 10 CFR 50.61. This regulation requires licensees of all operating PWRs to maintain licensed values of the reference temperature for pressurized thermal shock (RT_{PTS}) for each beltline material. These values must be below the screening values of 270°F for plates, forgings, and axial welds or below 300°F for circumferential welds. If RT_{PTS} values are projected to exceed the screening criteria, "the licensee shall implement those flux reduction programs that are reasonably practicable to avoid exceeding the PTS screening criterion." Additionally, licensees may subject the RV to thermal annealing or demonstrate compliance to PTS regulations via evaluation consistent with 10 CFR 50.61(a). Per WCAP-18242-NP, Units 1 and 2 are shown to meet the 10 CFR 50.61 screening criteria at 68 EFPY. Since the limiting RT_{PTS} values are greater than 15°F from the RT_{PTS} screening criteria values, Units 1 and 2 are expected to continue to meet the RT_{PTS} screening criteria past 68 EFPY.

The NRC's original position on PTS is summarized in Policy Issue SECY-82-465, which affirms through transient analysis and probability-weighted flaw distributions that the risk from PTS events for reactor vessels with RT_{NDT} values less than the proposed screening criterion is acceptable. It also provides, in significant detail, the basis for this conclusion, which includes an analysis of PTS transients. The PTS transients analyzed include main steam line break and small LOCA, amongst others.

A subsequent NRC study of PTS was published in NUREG-1874, which stated that "It is now widely recognized that the state of knowledge and data limitations in the early 1980s necessitated conservative treatment of several key parameters and models used in the probabilistic calculations that provided the technical basis for the current PTS Rule." NUREG-1874 confirms, through additional analysis of PTS transients, that the 10 CFR 50.61 methods and screening criteria are conservative.

NUREG-1874 provides quantitative analysis based on limiting the Through-Wall Cracking Frequency (TWCF) term for a vessel to 1×10^{-6} per reactor year, which is considered an acceptable risk, for multiple transients including a main steam line break. NUREG-1874 determines RT limits based on the TWCF limit. These RT limits are identical to those in 10 CFR 50.61a. Therefore, by mandatory compliance with 10 CFR 50.61a (or the more conservative 10 CFR 50.61), a low risk of vessel failure is ensured.

NUREG-1874 analyzed the main steam line break transient with respect to TWCF specifically, and concluded the following regarding the main steam line break transient:

> "...[E]ven though these transients produce an extremely rapid initial cooling rate of the RCS [reactor coolant system] inventory (as a result of the large break area) the minimum temperature of the RCS (the boiling point of water) is generally high enough to ensure a high level of fracture toughness in the vessel wall, thereby preventing MSLB [Main Steam Line Break] transients from contributing significantly to the total TWCF [through-wall cracking frequency] estimated for a plant."

The NRC PTS studies in SECY-82-465 and NUREG-1874 provide rigorous quantitative analysis demonstrating that PTS transients do not pose a significant risk if the mandatory requirements of 10 CFR 50.61 or 10 CFR 50.61(a) are met. Thus, since a main steam line break transient is considered a PTS transient, the Units 1 and 2 compliance with 10 CFR 50.61 inherently ensures beltline vessel integrity during this transient, particularly in the low temperature region.

Elastic-Plastic Fracture Mechanics Approach

PWROG-17031-NP followed the same linear elastic fracture mechanics (LEFM) methodology as is documented in WCAP-15338-A. LEFM conservatively idealizes the crack tip to be a sharp singularity and characterizes the crack tip using stress intensity factor, K, which depends on stress and crack geometry. A different approach to address the allowable flaw size is to use Elastic-Plastic Fracture Mechanics (EPFM), which removes conservatism in LEFM by considering crack tip blunting and calculates the applied J-integral around the crack tip. The calculated applied J-integral is compared to the J-material, a property that describes the material's ability to resist crack extension. ASME Section XI, Appendix K provides the EPFM analysis guidance and acceptance criteria. AREVA Report, BAW-2178, Supplement 1NP-A, performed an Equivalent Margins Analysis (EMA) for certain reactor vessel Linde 80 welds with projected 80-year upper-shelf energy (USE) below 50 ft-lb for multiple plants including Surry Units 1 and 2. EMA analysis uses the EPFM approach. The EMA uses stresses from SPS plant-specific finite element analyses and considers two steam line break transients, one of which is the Westinghouse generic large steam line break (LSB) transient from "Systems Standard Design Criteria 1.3." A very similar generic LSB transient was used in WCAP-15338-A for the allowable flaw size determination. Per ASME Section XI, K-2300, Level C/D, EMA postulates a flaw with depth equal to 1/10 base metal thickness plus cladding but no larger than 1.0 inch. The 0.67 inch allowable flaw size used in the underclad cracking evaluation, PWROG-17031-NP, is bounded by the accepted flaw depth in the base metal from the Surry EMA (Level C/D), BAW-2178, Supplement 1NP-A. Therefore, the EMA evaluations provide an additional level of assurance that an underclad crack would not cause a reactor vessel failure.

Summary

Through the combination of the allowable flaw size calculation, PTS considerations, and the use of EPFM, the issue of underclad cracking at SPS Units 1 and 2 has been analyzed from multiple perspectives. As a result, it is concluded that the existence of underclad cracks does not pose a risk to Units 1 and 2 plant operation for at least 80 years when using a fracture toughness of 200 ksi$\sqrt{in}$ as a conservative upper-shelf (or maximum) value for K_{Ic}.

RAI B2.1.6-1

Background:

Surry SLRA AMP B2.1.6, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program consists of the determination of the susceptible piping and piping

components in the reactor coolant pressure boundaries with respect to thermal aging embrittlement based on the casting method and chemical composition of the CASS materials. The aging management of the susceptible piping and piping components is accomplished through a component-specific flaw tolerance evaluation in accordance with ASME Code, Section XI. As part of the aging management program, the applicant submitted the following documents addressing the flaw tolerance evaluation in the CASS materials in the reactor coolant piping and piping components at the Surry, Units 1 and 2. The documents submitted in the portal are: (1) WCAP-18258, Flaw Evaluation for Susceptible Reactor Coolant Loop Cast Austenitic Stainless Steel (CASS)," (2) In-house audit response-NRC Audit for SPS'S SLR Information for TRP 12 CASS 3 4 19 Tomes".

Issue:

In Item 1 (7) of the report in the portal, "In-house audit response-NRC Audit for SPS'S SLR Information for TRP 12 CASS, 3 4 19 Tomes," the applicant stated that a postulated fatigue crack is located in the weld region at the ends of the elbow. The staff noted that there are locations within the elbow (such as the intrados, extrados, and cheek locations) that could have higher stresses than the ends of the elbow. The staff also noted that CASS pipes and elbows have a higher delta ferrite content and a lower strength than the weld metal. If the fatigue crack were to occur, it is more likely to occur in the lower strength region near the CASS base metal adjacent to the weld, but not in the weld.

Request:

Based on the issues the staff identified above, stresses could be higher in other locations within the elbow and these locations could have a higher delta ferrite content (and thus subject to a greater degree of thermal embrittlement than the locations the applicant selected for evaluation). The staff requests that the applicant justify the selection of the weld region at the ends of the elbows as the bounding locations for evaluation.

Dominion Response:

Dominion used criteria developed by ASME Code, Section XI for assessment of thermal aging embrittlement of cast austenitic stainless steel (CASS). The weld region at the ends of the elbows was chosen as the bounding location for the CASS flaw evaluation because the weld region (including 1/2-inch into the base metal, which is the heat affected zone of the straight pipe, i.e., not at the region of intrados or extrados) is the required area of examination per ASME Code, Section XI, Figure IWB-2500-8 for similar metal welds in piping (examination category B-J in ASME Code, Section XI, Table IWB-

2500-1). These weld regions have a higher likelihood of fabrication defects due to welding imperfection at the time of installation. The higher probability of detecting welding defects is one of the main reasons ASME Code, Section XI examination zones are for the weldments and the heat affected zones.

Similar guidance for selection of the weld region for flaw postulation and evaluation of CASS piping components (i.e., pipes and elbows) is also provided in ASME Code, Section XI, Code Case N-838, "Flaw Tolerance Evaluation of Cast Austenitic Stainless Steel Piping." As discussed in Section 1(b) of Code Case N-838, the scope is for flaw tolerance evaluations of postulated flaws in CASS base metal adjacent to welds in conjunction with license renewal commitments. More specifically, Section 3(b)(1) of Code Case N-838 states, "Select locations for postulating flaws in susceptible CASS piping adjacent to welds in accordance with the defined volume in Figure IWB-2500-8." Therefore, with the use of this code case for flaw tolerance evaluations, the flaws are always postulated in straight pipes at the ends of the elbows at the welds and not the elbow intrados/extrados. Code Case N-838 has been reviewed by the NRC without any condition on flaw postulation guidelines (10 CFR Part 50, NRC-2017-0024, Approval of American Society of Mechanic Engineers' Code Cases, Proposed Rule, Federal Registrar Vol. 83, No. 159, August 16, 2018). Thus, the flaw postulation in straight pipe in the vicinity of the examination zone of the weld as per ASME Code, Section IWB-2500-8 is acceptable. The technical basis for Code Case N-838 is MRP-362, Revision 1, and the flaw evaluation guidance in MRP-362 is also based on fracture mechanics of straight pipes, not of elbows.

The operating experience of CASS components (elbows and pipes) demonstrates the likelihood of fabrication flaws in the base metal is low. As discussed in MRP-362, Revision 1 (Section 4.1.1), CASS components have undergone pre-service inspection before installation. Historically, the NSSS vendor required that the pre-service inspections of these CASS components consist of both liquid penetrant examination and radiographic examinations during and after fabrication. During these pre-service inspections, typical defects may have been surface porosity, linear discontinuities, inclusions and shrinkage effects. In all cases when defects were identified during the pre-service examination, the defects were excavated to sound metal and repaired by welding, if needed. Therefore, prior to being placed in-service, the remaining defects in CASS piping satisfy ASME Code acceptance standards. Therefore, the probability of identifying any flaws in the CASS base metal is very low as compared to defects typically found in weld metals; as a result, the flaw postulation is typically performed for welds and the adjacent heat affected zones.

The "In-house audit response-NRC Audit for SPS SLR Information for TRP 12 CASS 3 4 19 Tomes", which was requested in RAI B2.1.6-2, is included in Enclosure 6, Attachment 1. The information delineated in Item 1 in the in-house audit response geometric stress indices for elbow intrados/extrados have been included in the transient stresses for Units 1 and 2 reactor coolant loop CASS elbow flaw evaluations. The geometric stress indices are applied to the mechanical (piping) loads, including pressure to account for the curvature of the elbow components which produces higher stresses within the elbow component. Per NB-3653.2 of Section III, through-wall stress due to thermal loads requires no adjustment due to the elbow curvature because the geometric stress indices applied to thermal loading are equal to 1.0 for curved pipe or butt welding elbows. Thus, the time-history through-wall transient stress profiles used in the Units 1 and 2 CASS flaw evaluations have included the effects of the elbow geometry and locations (such as the intrados, extrados, and cheek locations) that could have higher stresses than the ends of the elbow.

Even though the weld region is picked for the postulation of flaws (with the applied geometric indices for elbows), the percent delta ferrite content calculations and the subsequent thermal aging susceptibility screening determination in Section 3 of WCAP-18258-P was completed based on Surry specific Certified Material Test Reports (CMTR) chemistry values of the CASS elbow base metal. Thus, the percent delta ferrite content calculations have included the effects of the higher delta ferrite content of the CASS elbows.

As for the material properties, the limiting yield and ultimate strength of the base metal are used in the flaw tolerance evaluations. Per the guidelines in ASME Code, Section IX, QW-153, the stainless steel weld material is stronger than the CASS elbow material base metal (i.e., the base metal material A-351 Grade CF8M has lower material properties (yield and ultimate strength) compared to the weld). The specific yield and ultimate strength of the base metal have been used to calculate the maximum allowable end-of-evaluation period flaw size; thus, the more limiting material properties are included in the CASS flaw evaluations.

In conclusion, the CASS flaw evaluation included the effects of the curvature of the elbow, included the more limiting delta ferrite susceptibility of the A-351 Grade CF8M base metal elbow material, and considered the lower material properties of the base metal. Therefore, the selection of the weld region at the ends of the elbows as the bounding location for the flaw tolerance analysis is justified since the analysis considered the limiting inputs (stress and material properties) with consideration of both the weld and base metal.

RAI B2.1.6-2

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

RAI B2.1.7-2 (Clarifications for Programmatic Enhancement No. 7)

Background:

The program in SLRA AMP B.2.1.7, "PWR Vessel Internals," includes programmatic Enhancement No. 7. In this enhancement, the applicant states that "procedures will be revised to address expansion criteria when degradation occurs for clusters of baffle-former bolts." The enhancement also includes the following additional statement: "MRP 2018-002 identifies expansion criteria as a Needed requirement (per NEI 03-08) to include one-time visual (VT-3) examination of barrel-former bolts if large clusters of baffle-former bolts are found during the initial volumetric (UT) examination."[1] Additional "Expansion" criteria for performing ultrasonic test (UT) inspections of barrel-former bolts are given in Table 5-3 of EPRI Report No. 3002005349, Revision 1 (MRP-227, Revision 1).

Issue:

The staff understands that the program currently references two different sources for the acceptance criteria that will be applied to potential contingency inspections of the barrel-former bolts. As a result, the application does not clearly identify whether MRP-2018-002, MRP-227 Revision 1, or some other industry report will be used to establish the acceptance criteria to assess the inspection needs for the barrel-former bolts.

Request:

Clarify whether the acceptance criteria for initiating and performing potential "Expansion"-based inspections of the barrel-former bolts will be based on: (a) MRP-227, Revision 1, (b) MRP-2018-002, (c) the combination of the two reports (i.e., MRP-227, Revision 1, for UT inspections of the bolts and MRP-2018-002 for initiating VT-3 visual inspections of the bolts), or (d) an alternative report that provides the basis for inspecting the barrel-former bolts. If it is an alternate report, identify the source (report reference) that will be used to provide the acceptance criteria for initiating "Expansion"-based inspections of the barrel-former bolts, and clarify whether the report's methodology has been endorsed for use by the NRC or provide an appropriate justification for its use.

Footnote 1: The staff acknowledges that the term clusters in the enhancement is referring to a cluster of degraded bolts, as defined in NSAL 16-1, Revision 1 or in MRP-2017-009.

Dominion Response:

Acceptance criteria for initiating and performing expansion-based inspections of the barrel-former bolts will be based upon a combination of MRP-227, Revision 1, Table 5-3 for UT inspections of the barrel-former bolts and MRP-2018-002 items 3a and 3b for initiating VT-3 visual examinations of the barrel-former bolts.

The supplemental guidance in MRP 2018-002, Item 3.b, is the content that will be added to procedures for performing a one-time VT-3 visual examination of accessible barrel-former bolts adjacent to a large cluster of baffle-former bolt indications, as described in Enhancement #7.

The supplemental guidance of MRP 2018-002, Item 3.b is indicated below:

1. Confirmation that one or more large clusters of baffle-former bolts with unacceptable indications are detected by the UT inspection of the baffle-former bolts shall require a VT-3 visual examination of the accessible barrel-former bolts adjacent to the large cluster of baffle-former bolt indications within three refueling cycles. A large cluster is defined as any group of adjacent baffle-former-bolts at least 3 rows high by at least 10 columns wide, or at least 4 rows high by at least 6 columns wide where 80% or greater of the baffle-former-bolts have unacceptable UT indications or are visibly degraded.

   The barrel-former bolts adjacent to the cluster include:

   - Barrel-former bolts in the same area as the cluster of baffle-former bolts with indications if that area is projected radially onto the core barrel
   - Barrel-former bolts on the two rows above and the two rows below the projected area
   - Barrel-former bolts on each of the two columns of bolts that are circumferentially adjacent to the projected area.

2. Confirmation that more than 5% of the lower support column bolts actually examined contain unacceptable UT indications shall require UT inspection of the accessible barrel-former bolts within three refueling cycles of identifying lower support column bolts with unacceptable UT indications.

<u>RAI B2.1.7-3</u> (Minimum Inspection Coverages for Core Barrel Assembly "Expansion"-Category Welds Referenced in Enhancement Nos. 9 and 16)

<u>Background:</u>

The program in SLRA AMP B.2.1.7, "PWR Vessel Internals," includes programmatic Enhancement Nos. 9 and 16. Collectively, in these enhancements, the applicant states that the minimum EVT-1 visual inspection coverages for the core barrel assembly lower flange welds (LFWs), upper axial welds (UAWs), middle axial welds (MAWs), lower axial welds (LAWs), and upper girth welds (UGWs) is a minimum of 50% of the weld surface.

<u>Issue:</u>

It is not clear to the NRC staff that the proposed minimum inspection coverage of 50% is consistent with MRP 2018-026 which specifies: "a minimum coverage of 75% of the weld length on the surface being examined shall be achieved; however, for welds with limited access (Note 4), a minimum examination coverage of 50% of the weld length on the surface being examined shall be achieved".

<u>Requests:</u>

1. *For the Surry-specific RVI designs, clarify whether the MAWs and LAWs are restricted by the presence of a thermal shield, thermal panels, or other components located near the welds.*
2. *Provide the basis for applying a minimum EVT-1 coverage criterion of 50% for potential "Expansion"-based EVT-1 visual inspections that may be performed on the core barrel assembly UGWs, LFWs, and UAWs. If applicable, identify any components near the UGWs, LFWs, and UAWs that may: (a) restrict access to the components, and (b) limit the ability of Dominion to achieve a minimum 75% coverage criterion for the EVT-1 based contingency inspections of these weld components, as established in MRP 2018-026.*

<u>Dominion Response:</u>

<u>Response to RAI B2.1.7-3, Request 1:</u>

The examinations of the MAWs and LAWs are expected to be restricted by interference with the thermal shield due to weld locations and configurations that are similar to those for the LGW. The 2013 Unit 1 LGW examination was completed from the exterior of the core barrel. The total weld length was 433 inches, but only 305 inches were examined, resulting in 70.4% coverage. The coverage was limited by obstructions between the core barrel and the thermal shield. The same configuration existed for the 2014 Unit 2 LGW examination that resulted in 71.6% coverage. The 2013 and 2014 UGW

examinations did not experience this interference since they were performed from the interior of the core barrel. However, examinations of the MAW and LAW from the interior were not feasible due to interference with the baffle plate structure.

Response to RAI B2.1.7-3, Request 2:

The basis for the 50% "expansion" based EVT-1 coverage is MRP 2018-026, "Transmit Initial Industry Responses Regarding EPRI Technical Report MRP-227-Revision 1". Table 4 of MRP 2018-026 includes the following statement as Note 3 for the UGW, LFW, and UAW, "A minimum coverage of 75% of the weld length on the surface being examined shall be achieved; however, for welds with limited access, a minimum examination coverage of 50% of the weld length on the surface being examined shall be achieved,"

As described below, some access limitations have occurred during past examinations:

- The 2013 and 2014 UGW examinations on both units achieved 100% coverage due to the ability to perform the examination from the interior of the barrel.
- The Unit 1 2013 LFW examination achieved 82% coverage. The Unit 2 examination achieved 81.5% coverage. Examination coverage limitations from the exterior of the core barrel occurred due to the narrow gap between the core barrel and reactor cavity wall.
- The UAW has not been examined previously. Although not affected by the thermal shield, the UAW examination may experience limitations due to the narrow gap between the core barrel and reactor cavity wall.

RAI B2.1.8-1

Background:

In SLRA, Section B2.1.8, "Flow-Accelerated Corrosion," the applicant claimed consistency with the GALL-SLR Report AMP XI.M17, "Flow-Accelerated Corrosion." SLRA Section B2.1.8 states that the erosion activity implements the recommendation of EPRI 3002005530, "Recommendations for an Effective Program Against Erosive Attack." The "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements for GALL-SLR Report AMP XI.M17 discuss recommendations to monitor, detect, and trend degradation due to erosion mechanisms (e.g. cavitation, flashing, etc.). During the In-Office audit, the staff reviewed the program basis document ETE-SLR-2018-1311, "Surry Subsequent License Renewal Project – Aging Management Program Evaluation Report – Flow-Accelerated Corrosion,"

Revision 1, to evaluate whether the applicant is consistent with the GALL-SLR Report AMP XI.M17 recommendations for the flow-accelerated corrosion (FAC) program. In the document, the applicant stated that the FAC erosion module in CHECWORKS will be used to assist in the development of the inspection plan for the Erosion Control program.

Issue:

The staff has not previously reviewed EPRI 3002005530. Neither the Surry SLRA nor the applicant's procedures provide information that describes how the FAC erosion module within the CHECWORKS software will be used to model erosion, and how these results will be used in planning erosion inspections.

Request:

Provide a justification for how the FAC erosion module will meet the recommendations of the GALL-SLR with respect to monitoring effects of wall thinning due to erosive mechanisms (including methods to calculate wear rate), its use in planning inspections for erosive degradation, as well as for monitoring and trending potential degradation due to erosive mechanisms. Additionally, describe how the guidance in EPRI 3002005530 incorporates the use of the FAC erosion module into the Surry erosion program for the program elements described above.

Dominion Response:

The *Flow Accelerated Corrosion* program (B2.1.8) implements the recommendations of EPRI 3002005530, "Recommendations for an Effective Program Attack Against Erosive Attack," into the erosion module of the program consistent with the following:

- Erosion Susceptibility Evaluation and Wear Rate Calculations
- Inspection Planning
- Monitoring and Trending
- Erosion Module Features

Erosion Susceptibility Evaluation and Wear Rate Calculations

The basis for the erosion module is an Erosion Susceptibility Evaluation (ESE) that identifies components that require inspection due to potential wall thinning due to cavitation, flashing, liquid droplet impingement (LDI), and solid particle erosion (SPE). The ESE included each system that could be degraded by any of these four mechanisms. Exclusion criteria listed in Exhibit 1 below were utilized to evaluate and screen the systems. If exclusion was applicable, the appropriate abbreviation(s) were listed on a system-by-system basis. If any mechanism was applicable, that system was identified as a candidate for inspection.

The erosion module includes calculations of wear using the difference between the nominal pipe thickness (T_{nom}) and the minimum measured thickness (T_{min}). The calculated wear is divided by the length of time the component has been in service to determine a wear rate. That wear rate is used to determine the remaining service life based on a projection of reaching the minimum acceptable wall thickness. The projected remaining service life provides the basis for determining whether a component requires immediate replacement, a future re-inspection, or no further inspection.

Inspection Planning

Inspection planning is accomplished using the following considerations:

- Erosion Susceptibility Evaluation for each unit
- Input from operating experience reviews
- Previously replaced components
- Piping components that have been replaced due to erosion degradation at other Dominion units
- Components requiring re-inspection from previous inspections

Monitoring and Trending

Monitoring and trending includes the following tasks:

- Validating inspection data (if any data are questionable, the need for a re-inspection is identified)
- Determining the wear rate for each component
- Calculating the remaining service life for each component
- Reviewing inspection results to determine if predictions from previous extent-of-condition evaluations remain valid
- Performing evaluations of erosion degradation associated with infrequent operational alignments to determine the need to include additional components in the Erosion Susceptibility Evaluation
- Updating the Erosion Susceptibility Evaluation periodically based on changes in system operating parameters or configuration

Erosion Module Features

EPRI 3002005530 is included as a reference in the Erosion Control Program implementing procedure, and provides the basis used in the erosion module for:

- Selecting components to inspect
- Identifying inspection techniques and methodology for each component in the inspection plan
- Determining wear rate and remaining service life
- Determining the need for component replacement

EXHIBIT 1
Erosion Susceptibility Evaluation: Exclusion Criteria

Abbreviation	Reason	Description
Cavitation Exclusion Criteria		
ES	Superheated Fluid	Excluded due to fluid existing in an entirely gaseous state
EI	Infrequent Operation	Excluded due to fluid flow < 2% of plant operating time
EB	Below Vapor Pressure	Excluded due to fluid existing below the vapor pressure throughout the line
EO	Oil	Excluded due to low vapor pressure of oil in the line
ED	Design	Excluded due to specific design considerations to mitigate cavitation
EX	Cavitation Index	Excluded due to cavitation index >2.5
EC	Configuration	Excluded due to a lack of sudden reduction in pipe size or flow direction change
EM	Electrical or Mechanical System	Excluded due to electrical or mechanical system containing no fluid piping
Flashing Exclusion Criteria		
ES	Superheated Fluid	Excluded due to fluid existing in an entirely gaseous state
EI	Infrequent Operation	Excluded due to fluid flow < 2% of plant operating time
EB	Below Vapor Pressure	Excluded due to fluid existing below the vapor pressure throughout the line
EP	Above Vapor Pressure	Excluded due to fluid existing above the vapor pressure throughout the line
EM	Electrical or Mechanical System	Excluded due to electrical or mechanical system containing no fluid piping
LDI Exclusion Criteria		
ES	Superheated Fluid	Excluded due to fluid existing in an entirely gaseous state
EI	Infrequent Operation	Excluded due to fluid flow < 2% of plant operating time
EP	Above Vapor Pressure	Excluded due to fluid existing above the vapor pressure throughout the line
EV	Low velocity	Excluded due to velocity < 3 ft/s
EM	Electrical or Mechanical System	Excluded due to electrical or mechanical system containing no fluid piping

EXHIBIT 1
Erosion Susceptibility Evaluation: Exclusion Criteria

SPE Exclusion Criteria		
ES	Superheated Fluid	Excluded due to fluid existing in an entirely gaseous state
EI	Infrequent Operation	Excluded due to fluid flow < 2% of plant operating time
EV	Low velocity	Excluded due to velocity < 3 ft/s
EF	Filtered	Excluded due to filtering of solid particles out of the line
EM	Electrical or Mechanical System	Excluded due to electrical or mechanical system containing no fluid piping

RAI B2.1.8-2

Background:

In SLRA, Section B2.1.8, "Flow-Accelerated Corrosion [FAC]," the applicant claimed consistency with the GALL-SLR Report for the AMP XI.M17, "Flow-Accelerated Corrosion." The GALL-SLR Report "detection of aging effects" program element, states that guidance for inspection scope expansions, when unexpected or inconsistent results are identified in the initial sample scope, is described in the Electric Power Research Institute document NSAC-202L, Revision 4. Guidance in NSAC-202L, Section 4.4.6 "Expanded Sample Inspection" states that the reasons for any unexpected or inconsistent inspection results should be investigated by performing an updated FAC predictive analysis, conducting additional inspections, and making material determinations as appropriate. In addition, expanded sample inspections should include any component within two diameters of the affected component and "a minimum of the next two most susceptible components from the relative wear ranking in the same train as that containing the piping component displaying significant wear." During the In-Office audit, the staff reviewed the program basis document ETE-SLR-2018-1311, "Surry Subsequent License Renewal Project – Aging Management Program Evaluation Report – Flow-Accelerated Corrosion," and procedure ER-AA-FAC-102, "Flow-Accelerated Corrosion Inspection and Evaluation Activities," to evaluate whether the applicant is consistent with the GALL-SLR Report recommendations for the Flow-Accelerated Corrosion AMP. For the "detection of aging effects" program element, Section 3.4.2 of the program basis document states that an evaluation is performed to determine the extent of expansion and cites ER-AA-FAC-102, Section 3.9.4. In addition, Section 2.1 of the program basis document states that evaluations documenting various

activities including sample expansion are independently reviewed by a qualified FAC engineer. Procedure ER-AA-FAC-102, Section 3.9.4, "Inspection Scope Expansion," includes inspection expansion to components upstream and downstream of the degraded component but does not specify any distance. The procedure includes a review of any CHECWORKS model but does not include further discussion regarding the performance of an updated FAC analysis or include, as a minimum, the next two most susceptible components. To evaluate prior scope expansion documentation, the staff reviewed operating experience associated with the FAC Program outage summary documents ETE-CME-2017-0013, "Surry Unit 2, 2017 Refueling Outage, Results of the Flow-Accelerated Corrosion Program," and ETE-CME-2019-0002, "Surry Unit 1, 2018, Refueling Outage, Results of the Flow-Accelerated Corrosion Program," which provided examples of where ultrasonic thickness testing has detected unacceptable or inconsistent wall thickness values. The staff also reviewed condition report CR1096902 "Significant Wear Observed During FAC Inspection (5"-SGS-11-151)," to determine the extent of the scope expansion performed by the applicant when unexpected degradation is found as a result of inspections.

Issue:

It is unclear that the requirements of procedure ER-AA-FAC-102, Section 3.9.4 are consistent with the guidance in NSAC-202L, Section 4.4.6, regarding inspection scope expansion. The implementing procedure does not address consideration of performing an updated FAC predictive analysis or making material determinations. In addition, the distance for inspecting upstream and downstream is not discussed and the inclusion of a minimum of the next two most susceptible components from the relative ranking in the same train is not included. In addition, it is not clear that the FAC procedure includes an independent review of sample expansion documentation by a qualified FAC engineer as stated in SLRA Section B2.1.8. The staff notes that its review of operating experience document listed above did not provide information on how far upstream and downstream piping was inspected during a scope expansion, nor did they provide detail on whether the next two most susceptible components in the CHECWORKS model were inspected for potential FAC-related degradation.

Request:

Provide information regarding scope expansion activities to show that either the Surry FAC program implementation includes the guidance in NSAC-202L, Section 4.4.6, or provide bases to show that aging will be effectively managed without being consistent with the guidance in NSAC-202L, Section 4.4.6. Also, provide information regarding the implementation of independent reviews of evaluations documenting sample expansions by qualified FAC engineers, as stated in SLRA Section B2.1.8.

Dominion Response:

An enhancement will be added to the *Flow Accelerated Corrosion* program (B2.1.8) to confirm that inspection scope expansions are consistent with NSAC-202L, Section 4.4.6, and to confirm that independent reviews of inspection scope expansions are independently reviewed by a qualified FAC engineer. Specific additions will specify that inspection scope expansions include:

- Any component within two pipe diameters downstream of the component displaying significant wear, or within two pipe diameters upstream if that component is an expander or expanding elbow
- The two most susceptible components from the CHECWORKS relative wear rate ranking in the same train containing the piping component displaying significant wear
- Corresponding components from other trains
- Inspections of additional components until no additional components with significant wear are detected

SLRA Changes

SLRA Section B2.1.8 and Table A4.0-1, Item 8 are supplemented, as shown in Enclosure 5 to add Enhancement #2 as described above.

RAI B2.1.8-3

Background:

As supplemented by letter dated April 2, 2019, SLRA Table 3.3.2-6 "Bearing Cooling," was modified to address the potential for erosion in valve bodies constructed of several different materials. The supplement also states that cavitation in this system could be caused by valve throttling. Additionally, condition report CR1031398, "BC Valve – Indication of Cavitation," describes cavitation in a Unit 1 bearing cooling valve and notes that the valve was previously replaced in 2013 due to a pin hole leak in the valve body. This CR also notes that the current non-destructive examination strategy doesn't evaluate the valve body for wall thinning. The staff notes that condition report CR1026621, "2-BC-505 Has a Through-Wall Leak," describes a through-wall leak for the corresponding Unit 2 valve; however, the cause of the leak was not included in the summary documentation. The applicant's erosion susceptibility evaluation (ESE) (ETE-CME-2018-1002, Revision 1, "Transmittal of True North Consulting Technical Report BP-2017-0045-TR-01, Erosion Susceptibility Evaluation – Surry," September 2018) designated the bearing cooling system as not being susceptible to cavitation because

the cavitation index is greater than 2.5. The ESE states that the bearing cooling system is a closed-loop system which does not have large enough pressure drops for cavitation to occur. The staff notes that comments for other systems in the ESE identify the potential for cavitation and flashing downstream of throttle valves and orifices. The ESE indicates that the criteria for the cavitation index greater than 2.5 is "a rule of thumb" and cites a reference to a valve manufacturer publication. The associated implementing procedure, ER-AA-FAC-105, "Erosion Control Program," Section 3.1.1 states that the ESE is to be periodically updated based on relevant operating experience.

Issue:

Although operating experience indicates that valves in the bearing cooling system are susceptible to wall thinning due to cavitation, the ESEs for both units identify the bearing cooling system as not being susceptible to erosive mechanisms, including cavitation. The staff notes that the exclusion criteria for the "cavitation index" and "infrequent operation" parameters cited in the ESE are inconsistent with the corresponding criteria provided in the NRC-approved EPRI 112657, "Risk Informed Inservice Inspection Evaluation Procedure." Consequently, it is not clear to the staff that there are adequate bases for the exclusion criteria parameters used in the ESE.

Request:

Provide information regarding the bases for the ESE exclusion criteria. Include a discussion about the determination that the bearing cooling system is not susceptible to erosion mechanisms with a specific explanation for why operating experience does not appear to support the ESE determination. Also provide information regarding whether other systems determined to be not susceptible to erosion mechanisms could be similarly affected. Include a discussion regarding how operating experience has been considered by the current ESE.

Dominion Response:

The Erosion Susceptibility Evaluation (ESE) for both Units 1 and 2 was initially performed using design basis operating parameters and system alignment. Input for the ESE included the following tasks:

- A review of industry operating experience to determine plant locations with a history of erosion failure
- A review of plant operating experience and maintenance history to determine locations with a history of erosion failure
- A review of design flow rate and pressure drop for any potential effect on erosion susceptibility

The bearing cooling (BC) system was initially determined to not be susceptible to erosion based on the design operating parameters and configuration, and the absence of erosion failures. Normal alignment would involve having the affected BC system valves either fully open or fully closed. However, a change in plant operation at both Units 1 and 2 potentially increases erosion susceptibility in portions of the BC system. This operational change has resulted in using valves for throttling flow that could potentially cause erosion of the valve body. As a result of this susceptibility, the Units 1 and 2 ESEs have been revised to add three Unit 1 valves and two Unit 2 valves to the scope of components requiring inspection for indications of erosion.

Plant information has not indicated any other systems at Units 1 and 2 for which erosion susceptibility would be higher than stated in the ESEs.

The ESE for each unit is updated periodically based on relevant operating experience and changes in system operating parameters.

RAI B2.1.10-1

Background:

In its SLRA, Section 3.1.2.2.11(1), "Cracking due to Primary Water Stress Corrosion Cracking," the applicant stated that the Electric Power Research Insitute (EPRI) Report 3002002850, "Steam Generator Management Program: Investigation of Crack Initiation and Propagation in the Steam Generator Channel Head Assembly," dated October 2014, was applicable and bounds the steam generator (SG) divider plates at Surry because Surry has the most limiting SGs analyzed in the Report, namely Alloy 600 Model 51 SGs. SRP-SLR Section 3.1.2.2.11, "Cracking due to Primary Water Stress Corrosion Cracking," recommends actions to manage aging of divider plate assemblies depending on the material of the divider plate assemblies and whether industry analyses (i.e. the EPRI Report) are bounding for the applicant's unit(s). Because the Surry SGs were fabricated with Alloy 600 divider plates, the following recommendations from SRP-SLR are potentially applicable: 1. For units with divider plate assemblies fabricated of Alloy 600 or Alloy 600 type weld materials, if the analyses performed by the industry (EPRI [Electric Power Research Institute] 3002002850) are applicable and bounding for the unit, a plant-specific AMP is not necessary. 2. For units with divider plate assemblies fabricated of Alloy 600 or Alloy 600 type weld materials, if the industry analyses (EPRI 3002002850) are not bounding for the applicant's unit, a plant-specific AMP is necessary or a rationale is necessary for why such a program is not needed. A plant-specific AMP (one beyond the primary water chemistry and the steam generator

programs) may include a onetime inspection that is capable of detecting cracking to verify the effectiveness of the water chemistry and steam generator programs and the absence of PWSCC in the divider plate assemblies.

Issue:

SLRA Section 3.1.2.2.11(1) stated that the EPRI analysis is applicable and bounding for the Surry SGs because the divider plates and associated welds are fabricated from Alloy 600 materials, and because Surry has Model 51 SGs which are determined to be the most limiting SG model in the EPRI analysis. The staff recognizes that EPRI Report 3002002850 analyzed the Westinghouse Model 51 SGs as the most limiting SG model; however, due to parameters such as manufacturing tolerances and plant-specific transients/loading, plant-specific parameters may need to be verified in order to demonstrate that EPRI Report 3002002850 is applicable and bounding to the Surry SG divider plates.

Request:

Provide the justification, and supporting evaluation, that demonstrates the Surry SG divider plate assemblies are bounded by industry analyses. Include a discussion of potentially plant-specific parameters discussed in EPRI Report 3002002850 (e.g., SG geometry, materials of components, cracking scenarios, plant-specific transient loads and cycles).

Dominion Response:

On October 10, 2016, EPRI issued letter SGMP-IL-16-02, "Guidance for Addressing Aging Management Plans for Steam Generator Channel Head Components," to inform the industry that the NRC had issued draft interim staff guidance (ISG) document, LR-ISG-2016-01, "Changes to Aging Management Guidance for Various Steam Generator Components," The ISG accepted the conclusions of the Steam Generator Management Program's (SGMP) investigation into the initiation and propagation of cracking in the steam generator channel head components, which is documented in EPRI Report 3002002850. EPRI letter SGMP-IL-16-02 states; "For units with divider plate assemblies fabricated with Alloy 600 or Alloy 600 weld materials, if the analyses performed by the industry are applicable and bounding for the unit, a plant-specific AMP is not necessary." Attachment 1 to EPRI letter SGMP-IL-16-02 is a checklist that utilities may use to document that the analyses in EPRI 3002002850 are bounding. The steam generator divider plate assemblies at SPS are bounded by EPRI Report 3002002850, as confirmed by completion of Attachment 1 to SGMP-IL-16-02. The plant-specific parameters addressed in the checklist include dimensional assumptions for the divider plate, channel head, tube sheet and stub runner; material assumptions for the bottom

head and cladding, upper vessel wall, tube sheet, stub runner, divider plate and welds; and design and transient loads. The SPS steam generators conform to each of these items in the checklist. Additionally, the checklist includes items that are applicable to the evaluation of PWSCC in Tube-to-Tubesheet Welds. This topic is not applicable to SPS, because alternate repair criteria H* has been approved for SPS such that the tube-to-tubesheet welds are no longer part of the reactor coolant pressure boundary. Therefore, the *Steam Generators* program (B2.1.10) is used to manage cracking within the channel head assembly, and a plant-specific program is not needed.

A completed copy of Attachment 1 to SGMP-IL-16-02 and a table including a comparison of associated design and transient EPRI cycle assumptions with SPS cycle limits are provided in Enclosure 6, Attachments 2 and 3.

RAI B2.1.10-2

Regulatory Basis

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

Background:

SLRA Section B2.1.10 states that the Steam Generators program is consistent with GALL-SLR Report AMP XI.M19, "Steam Generators" without exceptions and enhancements. As amended by letter dated April 2, 2019, SLRA Table 3.1.2-4 was modified to remove items managing cracking for steel with stainless steel cladding channel heads (and cladding), and loss of material for steel with stainless steel cladding primary inlet nozzle and outlet nozzles (and cladding).

The SRP-SLR Section 3.1, "Aging Management of Reactor Vessel, Internals, and Reactor Coolant System," addresses the AMRs associated with certain steam generator

components. This section includes the components discussed above, as well as the recommended AMPs to manage aging effects associated with these components.

Issue:

Table 3.1.2-4, as amended by letter dated April 2, 2019, no longer cites programs to manage cracking for the steel with stainless steel cladding channel head (and cladding), and only cites the Water Chemistry program to manage loss of material for the steel with stainless steel cladding primary inlet nozzle and outlet nozzle (and cladding).

Amended Table 3.1.2-4 no longer includes cracking as an aging effect requiring management for the SG channel head (and cladding). GALL-SLR identifies cracking as an applicable aging effect for steel with stainless steel cladding. For example, GALL-SLR Item RP-232 identifies cracking of steel with stainless steel cladding exposed to reactor coolant as an applicable aging effect to be managed using AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" and AMP XI.M2, "Water Chemistry.".

Amended Table 3.1.2-4 now references Table 1 Item 3.1.1-088 to manage loss of material for steel with stainless steel cladding primary inlet and outlet nozzles (and cladding) exposed to reactor coolant using the Water Chemistry program. However, GALL-SLR Item R-436 recommends using AMP XI.M2, "Water Chemistry" and AMP XI.M19, "Steam Generators" to manage loss of material for steel with stainless steel cladding exposed to reactor coolant.

Request:

1. *Explain which program(s) will be used to manage cracking in steel with stainless steel cladding channel heads (and cladding) or state the basis for why a program is not necessary.*
2. *Are other programs besides the Water Chemistry program used to manage loss of material in steel with stainless steel cladding primary inlet nozzle and outlet nozzles (and cladding)? If not, explain how the Water Chemistry program alone with manage the loss of material without an inspection program (such as the Steam Generator program) to verify effectiveness of the Water Chemistry program.*

Dominion Response:

Response to RAI B2.1.10-2, Request 1:

Cracking in steel with stainless steel cladding channel heads (and cladding) will be managed with the *Steam Generators* program (B2.1.10). Inspection requirements for cracking of channel heads are addressed by the steam generator degradation assessments performed in accordance with the *Steam Generators* program.

Response to RAI B2.1.10-2, Request 2:

Loss of material in steel with stainless steel cladding primary inlet nozzle and outlet nozzle (and cladding) is managed with the *ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1).

SLRA Changes

SLRA Table 3.1.1 item 127 and Table 3.1.2-4 are supplemented, as shown in Enclosure 5, to indicate the changes noted above.

RAI B2.1.11-1 Generic Letter 89-13 Commitments

Background:

GALL-SLR AMP XI.M20, "Open-Cycle Cooling Water System," states that the inspection scope, methods, and frequencies are in accordance with the applicant's docketed response to Generic Letter (GL) 89-13, "Service Water System Problems Affecting Safety-Related Components." SLRA Section B2.1.11, "Open-Cycle Cooling Water System," states that the program is an existing program that, following enhancement, will be consistent with the GALL-SLR AMP XI.M20. SLRA Section B2.1.11 also states that periodic heat transfer testing, visual inspection, and cleaning of safety-related heat exchangers is performed in accordance with the site commitments to GL 89-13. ETE-SLR-2018-1314, "Aging Management Program Evaluation Report – Open-Cycle Cooling Water System," Revision 2, documents and evaluates the activities in the associated AMP that are credited for managing aging as part of Surry's SLRA. ETE-SLR-2018-1314 discusses a discrepancy between Surry's response to GL 89-13 (letter dated October 2, 1991 (89-572G)) and the maintenance strategy implementation for the charging pump lube oil coolers. The maintenance strategy changed from periodic replacement of charging pump lube oil coolers to performing routine inspection and maintenance. ETE-SLR-2018-1314 states that the discrepancy was evaluated in accordance with the commitment change evaluation process and cites corrective action CA3022000 "Submit Commitment Change Paperwork to Update Requirements for Charging Pump LO [Lube Oil] Coolers" (March 9, 2017). The staff noted that the change in maintenance strategy affected the scope of Surry's Open-Cycle Cooling Water System program, because components that are periodically replaced are excluded from the scope of an aging management review for license renewal. In response to staff questions for CA3022000, Surry posted condition report CR1091365, (March 6, 2018). "A Commitment Change Evaluation Was Completed and Approved Mistakenly." The condition report states that the commitment change evaluation was "for a change made to a response to the NRC, not a commitment to the NRC." The actions discussed in the

condition report included a clarification regarding "the difference between a response and a commitment to the NRC." During its review of ER-SU-5314, "Generic Letter 89-13 Program," Revision 2, the staff noted that Attachment 1, "Generic Letter 89-13 Components and Commitments," includes a table for each set of components in the program and includes a column labeled "Commitment Source." Every set of components in the list includes "Letter to NRC 10/2/91 Serial Number 89-572G" as the source of the commitment to perform the specified GL 89-13 activity. However, the table's initial note states that the letter dated April 30, 1991 (Serial 89-572E), summarized the GL 89-13 program and that the response was updated by letter dated October 2, 1991 (Serial 89-572G), "which supersedes Serial Number 89-572E. No new commitments were made." The staff notes that the letter dated April 30, 1991 (Serial 89-572E), states that a "detailed revision of [Surry's] initial January 29, 1990, response incorporating the subsequent supplements and the additions integrated into this summary description will be separately forwarded." In addition, the staff notes that none of the GL 89-13 response letters appear to specifically identify the site's activities for periodic heat transfer testing, visual inspection, and cleaning of safety-related heat exchangers as being "commitments."

Issue:

Because none of the site's GL 89-13 response letters appear to specifically identify the commitments for periodic heat transfer testing, visual inspection, and cleaning of safety-related heat exchangers, the staff was unable to verify that the Open-Cycle Cooling Water System program would be performed in accordance with the site's commitments to GL 89-13. The program documentation appears to cite the letter dated October 2, 1991 (89-572G), as the source of the site's GL 89-13 commitments. However, the recent condition report (CR1091365) states that because the information in the October 2, 1991, letter was only a response to GL 89-13 and not a commitment, there was no need to perform a commitment change evaluation for changing the approach discussed in the October 2, 1991, letter. Based on the position discussed in CR1091365, the staff is unsure of the site's GL 89-13 commitments.

Request:

Provide additional information to clarify the site's GL 89-13 commitments. Include information about which prior GL 89-13 response letter(s) to the NRC contain(s) the commitments that are discussed in SLRA Section B2.1.11. If the source of Surry's commitments to GL 89-13 are not from the response dated October 2, 1991 (89-572G), also include information regarding the circumstances about why ER-SU-5314, "Generic Letter 89-13 Program," Revision 2, cites the letter dated October 2, 1991 (89-572G).

Dominion Response:

The response provided in letter Serial No. (SN) 89-572G is considered the source of the commitments for Surry in response to Generic Letter (GL) 89-13. ER-SU-5314, Revision 2, is the Guidance and Reference Document (GaRD) for the Surry GL 89-13 Program. The purpose of the GaRD is to define Surry's commitments to GL 89-13. Attachment 1 to ER-SU-5314 summarizes the Surry commitments to GL 89-13 and cites SN 89-572G as the commitment source for each entry, except one, in the attachment. Page 3 of 12 of Attachment 1 reflects maintenance or replacement of the charging pump lube oil coolers.

As noted in the Background for RAI B.2.1.11-1, a Commitment Change Evaluation (CCE) was performed to assess the change in maintenance strategy for the charging pump lube oil coolers from replacement (documented in SN 89-572G) to inspection and maintenance or replacement. When this CCE was reviewed for inclusion in the annual report of 10CFR50.59 evaluations and CCEs to the NRC, it was concluded that the CCE was not required and CR1091365 was submitted. This conclusion was reached in part due to the confusing wording in SN-572G that states "this revision contains no new commitments nor modifies previously specified ones." Note that SN 89-572E identified inspection and maintenance, as required, for the charging pump lube oil coolers; SN 89-572G indicated that inspection and maintenance of these coolers are not performed and that cooler maintenance is accomplished by replacement. Upon further review, it has been determined that the CCE to change the maintenance strategy for the charging pump lube oil coolers from replacement (documented in SN 89-572G) to inspection and maintenance or replacement is a valid change in commitment. As noted herein, inspection or replacement of the charging pump lube oil coolers is reflected in ER-SU-5314.

RAI B2.1.11-2 AMR Items for Open-Cycle Cooling Water System

Background:

SLRA Section B2.1.11, "Open-Cycle Cooling Water System," states that periodic heat transfer testing, visual inspection, and cleaning of heat exchangers are performed in accordance with the site commitments to GL 89-13 to verify heat transfer capabilities. SLRA Section B2.1.11 also includes an enhancement to the monitoring and trending program element to revise procedures to require trending the inspection results of the emergency service water pump engine heat exchangers. The staff notes that ER-SU-5314, "Generic Letter 89-13 Program," Revision 2, includes the emergency service

water pump engine heat exchanger and specifies associated activities for periodic heat transfer testing, as well as inspection and maintenance. In addition, ER-SU-5314 includes the emergency service water pump angle drive and specifies that heat transfer is checked during monthly surveillance testing, and that cooling water flow is verified during inspection and maintenance activities. Although SLRA Table 3.3.2-4 "Service Water – Aging Management Evaluation," includes other emergency service water pump components, it does not appear to include the emergency service water pump engine heat exchanger or the emergency service water pump angle drive.

Issue:

Although SLRA Section B2.1.11 includes an enhancement to trend inspection results associated with emergency service water pump engine heat exchangers, the SLRA does not appear to include a corresponding aging management review item(s). In addition, although Surry's GL 89-13 program appears to specify activities to address heat transfer for the emergency service water pump angle drive, the SLRA does not appear to include a corresponding aging management review item.

Request:

For the emergency service water pump engine heat exchangers and the emergency service water pump angle drives, provide information showing that assessment of the heat transfer capabilities of safety-related heat exchangers (with a heat transfer intended function) will be performed by the SLRA Section B2.1.11, "Open-Cycle Cooling Water System" program, in accordance with site commitments to GL 89-13. Include information showing either 1) that existing aging management review items with corresponding aging effects are included in the SLRA for these components or 2) that aging management review items are not needed for these components, to demonstrate that the effects of aging will be adequately managed.

Dominion Response:

The emergency service water (ESW) pump diesel engine is an active skid mounted assembly consistent with the engine component of NUREG-2192, Table 2.1-6. Each ESW pump diesel engine is designed to provide the required horsepower to achieve the required ESW pump flow. The integral heat exchanger supplies cooling water to the engine components of its specific diesel engine.

The lube oil system is internal to the ESW pump engine. The evaluation boundary was established as follows:

- The inlet and outlet connections to the service water system on the ESW pump diesel engine heat exchanger. The connecting hoses are part of the ESW system.
- The fuel oil inlet and return connections to the ESW pump diesel engine. The connecting tubing and flexible hoses are part of the ESW fuel oil system.

Following is a description of the ESW pump diesel engine heat exchangers and the pump diesel engine angle drive to facilitate a better understanding of their operation and location within the skid assembly.

<u>ESW Pump Diesel Engine Heat Exchangers</u>
The engine heat exchanger core consists of a series of cells with a header at one end and a circular water outlet at the opposite end. The core is mounted inside of the expansion tank with the header or inlet end bolted to the tank and the opposite or outlet end is sealed inside a retainer. In this system of engine cooling, the hot coolant leaving the thermostat housing passes through the expansion tank, then through the cells of the cooling core. After leaving the heat exchanger, the engine coolant is picked up by the fresh water pump and circulated through the cylinder block and cylinder heads. The raw water is forced horizontally between the cells of the core and serves to lower the temperature of the coolant as it passes through the cells. The engine heat exchanger is mounted directly to the end of the engine.

<u>ESW Pump Diesel Engine Angle Drive</u>
The angle drive is supplied with a counter flow oil cooler with ½ inch standard pipe connections. The cooler is located inside the motor stand. Small engines (such as those associated with the emergency service water pumps) were classified as active assemblies, and also treated the gear drive oil cooler as part of the active engine/drive train assembly. Vendor technical manuals for the engine and for the angle drive confirm the heat exchangers associated with the engines (turbocharger inter and after coolers, oil cooler, engine jacket, and raw/coolant HX) and with the angle drive are integral components that are internal to or mounted directly to the active assemblies.

The convention of evaluating small diesel engine skid mounted components as active assemblies is consistent with practices used by other applicants. In accordance with 10 CFR 54.21(a)(1)(i) aging management review of active assemblies is not required. Therefore, aging management of the ESW pump diesel engine heat exchangers and the pump diesel engine angle drive is not required.

However, evaluating the heat exchangers as part of the active assemblies does not exempt them from any monitoring commitments associated with Generic Letter 89-13 commitments, and those commitments remain in effect during the subsequent period of extended operation.

The design heat transfer capability of the ESW pump diesel coolers is greater than that required to remove design heat load. Specifically, to demonstrate the heat transfer capability of the ESW pump diesel engine, Periodic Tests are performed monthly on the ESW pump diesel engine, which requires manipulation of the service water throttle valve to adjust water temperature. Failure to achieve the temperature criteria with the service water throttle valve fully opened prompts a strainer change and cleaning of the previously inservice strainer basket. Normal heat loads and design tube side temperature differentials are insufficient to achieve accurate results in heat transfer performance testing.

Maintenance of the gear oil cooler is performed routinely.

RAI B2.1.15-1

Background:

SLRA Section B2.1.15 states that the Fire Protection program is consistent with GALL-SLR Report AMP XI.M26, "Fire Protection," with no exceptions or enhancements. GALL-SLR Report AMP XI.M26, "Fire Protection" states that the Fire Protection program manages the effects of loss of material and cracking for fire damper assemblies, among other components. The recommended description in GALL-SLR Report Table XI-01 states that the Fire Protection program requires periodic visual inspection of fire damper assemblies, among other components. GALL-SLR Report Item A-789 (SLRA Table 3.3-1, item 3.3.1-255) identifies the aging effects as "[l]oss of material due to general, pitting, crevice corrosion; cracking due to SCC; hardening, loss of strength, shrinkage due to elastomer degradation."

SLRA Section A1.15, "Fire Protection" and B2.1.15, "Fire Protection" both use the term "fire damper housing." The AMR items in Table 3.3.2-29, "Auxiliary Systems – Ventilation – Aging Management Evaluation," that cite Table 3.3.1, Item 3.3.1-255 identify only the "housing" as a component with aging effects requiring management. In addition, these items cite plant-specific note 3, which states: "[t]his row is applicable to fire dampers. Cracking, hardening and loss of strength, and shrinkage are not aging effects requiring management for steel fire dampers exposed to indoor air."

Issue:

The term "fire damper assembly" includes both the frame and the damper as evidenced by the aging effects requiring management as cited in item A-789. For example, hardening and loss of strength would not be applicable aging effects if the intent of the GALL-SLR Report were to only manage aging effects associated with housings, which are typically constructed of steel materials. Whereas "fire damper housing" includes just the frame, as evidenced by plant-specific note No. 3. Plant-specific note 3 is not consistent with GALL-SLR Report item A-789. The SLRA lacks a basis for why aging effects will only be managed for the housing versus the damper assembly.

Request:

State the material of construction for the fire damper assemblies other than the housing that perform their intended isolation function in the closed position and the basis for why the aging effects cited in GALL-SLR Report Item A-789 are not applicable to portions of the fire damper assembly other than the housing.

Dominion Response:

Fire damper assemblies (both the housing and other portions that perform their intended isolation function in the closed position) are made of steel. Dominion will manage loss of material for fire damper assemblies (both the housing and other portions that perform their intended isolation function in the closed position) using the *Fire Protection* program (B2.1.15). Other aging effects cited in NUREG-2191, Item A-789 are not applicable to steel.

SLRA Changes

Based on the above, SLRA Tables 2.3.3-29 and 3.3.2-29 are supplemented, as shown in Enclosure 5, to include aging management of the ventilation system steel fire damper assembly for loss of material with the *Fire Protection* program (B2.1.15).

RAI B2.1.15-2

Background:

SLRA Section B2.1.15 states that the Fire Protection program is consistent with GALL-SLR Report AMP XI.M26, "Fire Protection," with no exceptions or enhancements. The monitoring and trending program element GALL-SLR Report AMP XI.M26 recommends, in part, that results of inspections are trended to provide for timely detection of aging effects and, where identified degradation is projected until the next inspection. In addition, results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions. The

acceptance criteria program element in GALL-SLR Report AMP XI.M26 recommends specific acceptance criteria for indications of degradation on fire protection components. Examples include, no visual indications (outside those allowed by approved penetration seal configurations) of cracking, separation of seals from walls and components, separation of layers of material, or ruptures or punctures of seals and no significant indications of cracking and loss of material of fire barrier walls, ceilings. The corrective actions program element in GALL-SLR Report AMP XI.M26 recommends that, the scope of inspection is expanded to include additional penetration seals in accordance with the plant's approved fire protection program should any sign of degradation be detected within the sample of inspected penetration seals. The program element also recommends adjusting inspection frequencies in the event that projected inspection results will not meet acceptance criteria prior to the next scheduled inspection.

Issue:

Based on the staff's review of plant-specific procedures associated with fire protection, the recommendations cited in the three program elements cited above are not included. SLRA Section B2.1.15 does not include enhancements to incorporate these recommendations. The SLRA does not include a basis for why these recommendations have not been addressed.

Request:

Identify the procedures that address the monitoring and trending, acceptance criteria, and corrective actions program elements as described in GALL Report AMP XI.M26 or state the basis as to why the Fire Protection Program is consistent with AMP XI.M26 as-is.

Dominion Response:

Monitoring and trending, acceptance criteria and corrective actions program elements of the *Fire Protection* program (B2.1.15) are addressed as follows:

Monitoring and Trending

Procedures will be enhanced to require an assessment for additional inspections to be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation. For sampling-based inspections, results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation.

Station procedures verify the performance of and demonstrate operability of the carbon dioxide and halon systems every 18 months by confirming air flow is detected at system nozzles. Carbon dioxide and halon systems air flow testing procedures will be enhanced to trend air flow test data.

Acceptance Criteria

The Technical Requirements Manual (TRM) requires surveillance of approximately 20% of fire-rated barriers and fire-rated penetration seals to be confirmed functional by detailed inspection. The frequency of the surveillance is every twelve months such that 100% of fire-rated barriers and fire-rated penetration seals are inspected every five years. Also, the TRM requires verification that fire doors and dampers are functional by inspection every 18 months. Further, fire barriers and penetration seals are required to be verified functional by detailed inspection following repairs or maintenance.

<u>Seals</u>
Acceptance criteria regarding cracking, spalling, and loss of material are met if the fire barrier or penetration seal does not appear to be compromised, materials are dimensionally intact, no light is visible through the penetration, and passage of air through the penetration is not detectable. There should be no gaps greater than 1/8 inch in the material covering a seal or evidence of rips, tears, or cracks.

<u>Damming Material Covering Seals</u>
The damming material covering seals is inspected for material rips, tears, or cracks. Also, gaps in material covering seal, missing anchor bolts, and holes other than small vents do not meet the acceptance criteria.

<u>Fire Barrier Walls, Ceilings and Floors</u>
Inspections of the integrity of fire barrier walls, ceilings, and floors check for evidence of spalling, cracks (other than hairline cracks), and loss of material.

<u>Dampers</u>
During fire damper operability testing, visual inspection is performed and any indication of loss of material is identified and evaluated. Procedures will be enhanced to require fire damper assemblies (rather than fire damper housings) to be visually inspected for loss of material and determined to be acceptable if there are no signs of degradation that could result in loss of fire protection capability due to loss of material.

<u>Doors</u>
Fire doors are verified to have no signs of breaks or open holes in the face of the door. The doors are verified to open fully, self-close and latch, and be clear of materials that could obstruct or interfere with the free operation of the door.

Halon/CO2 Fire Suppression

Periodic visual inspections of the surface conditions for the halon and CO_2 fire suppression systems performed during air flow testing will be enhanced to specify that inspection results are acceptable if there are no indications of excessive loss of material.

Corrective Actions

Procedures will be enhanced to require if degradation is detected within the inspection sample of penetration seals, the scope of the inspection is expanded to include additional seals in accordance with the plant's Corrective Action Program. Additional inspections would be 20% of each applicable inspection sample; however, additional inspections would not exceed five. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the site's Corrective Action Program.

SLRA Changes

SLRA Section B2.1.15 and Table A4.0-1, Item 15 are supplemented, as shown in Enclosure 5, to add Enhancements 1 through 3. In addition, SLRA Table B2.1 is supplemented, as shown in Enclosure 5, to indicate that the *Fire Protection* program (B2.1.15) requires enhancement.

RAI B2.1.17-1

Background:

On April 24, 2019, NRC staff performed a walkdown of the emergency condensate storage tanks (ECSTs). During the walkdown, water was identified around one of the weep drainage holes for the Unit 2 ECST, whereas the remaining weep holes did not have any condensation present. Condition Reports 1121772 and 1121803 state that: (a) a similar condition existed on the Unit 1 ECST; and (b) a sealant will be installed on the missile shield to prevent water intrusion which could cause external corrosion of the tank and potential damage to the external insulation. The condition reports also state that internal inspections of the Unit 1 and Unit 2 ECSTs were completed in 2013 and 2017, respectively, and did not document any concerns regarding the external or internal condition of the tanks. The detection of aging effects program element in GALL-SLR AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks" states, in part, that "[i]f the exterior surface is not coated, visual inspections of the tank's surface are conducted within sufficient proximity to detect loss of material" and "[i]f the exterior surface of an outdoor tank or indoor tank exposed to condensation is insulated,

sufficient insulation is removed to determine the condition of the exterior surface of the tank." SLRA Section B2.1.17 states an exception to conducting visual and volumetric examinations of the external surfaces of the ECSTs due to the concrete missile shielding and expansion joint filler foam surrounding the tank. The concrete missile shields do not allow visual examinations of the tank's external surfaces as recommended by AMP XI.M29.

Issue:

The duration of the presumably ongoing leakage through the missile shields is unknown. In addition, a review of station drawings indicated that the plug was located above the tank such that any leakage that managed to penetrate the external joint filler foam between the missile barrier and tank could potentially wet the external surface of the tank. Because the tanks are contained within a concrete missile barrier with insulation between, any leakage that penetrates to the surface of the tank could be retained for an extended period, potentially corroding the external surface of the tank. The summary of the inspections conducted in 2013 and 2017 lacks sufficient detail to justify why external corrosion has not occurred on the tanks as a result of the ongoing leakage. For example, an internal inspection will not detect external corrosion unless a volumetric wall thickness inspection was conducted. Because of this plant-specific operating experience, SLRA Section B2.1.17 lacks a sufficient basis to justify the exception to AMP XI.M29.

Request:

State the basis for tank integrity will be maintained throughout the SPEO despite the potential for condensation being retained on the surface of the tank and a lack of visual confirmation to prove otherwise.

Dominion Response:

Consistent with CR1121772 and CR1121803, flex seals will be installed and leak checked at the removable access plug on the concrete missile shield for the SPS Unit 1 and Unit 2 ECSTs to prevent water leakage into the annular space between the steel tank and the concrete missile shield. The removable access plug is located on the outside diameter of each ECST such that there is the potential for water leakage to drain down the slope of the ECST steel roof and the vertical side of the tank closest to the removable access plug and be visible in one or more of the three weep holes at the base of the concrete missile shield vertically below the removable access plug. A leakage check of the removable access plug seal will be performed by inspecting the concrete missile shield weep holes vertically below the removable access plug after a rain shower to confirm the integrity of the removable access plug seal.

Enhancement #3 of the *Outdoor and Large Atmospheric Metallic Storage Tanks* program (B2.1.17) will be revised to require one-time thickness measurements of a sample of the ECSTs vertical wall prior to the subsequent period of extended operation to assess potential degradation in the unlikely event of leakage from the removable access plug. The sample will examine the ECST vertical steel shell region between the three weep holes at the tank bottom associated with removable access plug leakage and vertically from that tank bottom junction to a distance of six feet along the vertical shell at the tank as a region potentially most susceptible to degradation. The inspection results will be projected to the end of the subsequent period of extended operation to confirm the ECSTs intended functions will be maintained throughout the subsequent period of extended operation based on the projected rate of degradation. Any degradation not meeting acceptance criteria will require periodic 10-year thickness measurements and a sample expansion along the leakage path consistent with the observed degradation. For example, degradation not meeting the acceptance criteria along the junction of the vertical shell at the tank bottom shell will result in a sample expansion horizontally along the vertical shell and bottom shell junction.

The *Outdoor and Large Atmospheric Metallic Storage Tanks* program (B2.1.17), following enhancement, as shown in the original SLRA submittal dated October 15, 2018, will require periodic inspection of ECST weep holes for water leakage/condensation once each refueling cycle and corrective action taken if excessive leakage is observed.

The activities described above will manage aging of the external steel surfaces of the SPS Unit 1 and Unit 2 emergency condensate storage tanks (ECSTs) throughout the subsequent period of extended operation.

<u>SLRA Changes</u>

SLRA Section B2.1.17 and Table A4.0-1, Item 17 are supplemented, as shown in Enclosure 5, to revise Exception #2 and Enhancement #3 to include the ECST thickness measurements described above.

RAI B2.1.23-1

Background

SLRA Section B2.1.23, "External Surfaces Monitoring of Mechanical Components," states that after enhancements the existing program will be consistent with GALL-SLR Report XI.M36, "External surfaces Monitoring of Mechanical Components." During a review of plant-specific operating experience (CR565668 – "Pipe Tunnel CC Pipe External Corrosion"), the staff noted that loss of material had occurred on the outside

surface of the component cooling water (CC) system piping between the pipe and the pipe supports. During clarification discussions, the applicant explained that the general problem was identified as part of the initial license renewal inspections and was addressed through the Infrequently Accessed Area Inspection Activities program. As documented in plant issue S-2002-1794-E1 – "Turbine Building to Auxiliary Building Pipe Tunnel," inspection of concrete surfaces at the ends of the turbine/auxiliary-building tunnel revealed ground water in-leakage due to a defect in the tunnel structure. The inspections at that time identified standing water that created an environment conducive to degradation of steel components within the tunnel. Although the external environment in this area would typically be considered as uncontrolled indoor air, Design Change DC-SU-13-00008 – "CC Pipe Replacements" notes that due to their location near the floor in the turbine/auxiliary-building tunnel, the component cooling water pipes designated as 18-CC-229-121 and 18-CC-235-121 were subject to damp and wet conditions for a number of years, causing corrosion on the outside surfaces of the pipes. DC-SU-13-00008 also notes that the replacement of pipe 18-CC-229-121 was completed in 2015.

The condition report from 2014 (CR565668) notes that wall thickness readings at a pipe support on 18-CC-229-121, which was not accessible until the associated section of piping was removed during scheduled replacement, showed isolated spots below minimum wall thickness. The condition report states that the overall compensatory measures for the similarly located pipe 18-CC-235-121, which includes yearly wall thickness measurements and quarterly walkdowns of the pipe in the pipe tunnel, should continue until the pipe is restored to maintain piping integrity.

Issue

As noted in SRP-SLR, Appendix A.1.2.3.10, operating experience for existing programs, including corrective actions that result in program enhancements or additional programs, should be considered. The staff considers the corrective actions to perform the more frequent visual inspections to monitor the environmental conditions in the turbine/auxiliary-building tunnel and the periodic wall thickness measurements of the degraded piping as ongoing condition monitoring activities that manage the effects of aging. Although corrective actions have been initiated to resolve the cause of the degradation, the staff could not determine the overall extent and effectiveness of these actions, based on the documentation provided. In addition, the staff could not determine whether the ongoing aging management activities, which are beyond those specified in the External Surfaces Monitoring of Mechanical Components program, will continue to be performed into the subsequent period of extended operation.

Request

Provide information discussing the actions taken and their overall effectiveness to address the adverse external environmental conditions in the turbine/auxiliary-building tunnel. Include a discussion whether other activities from the Infrequently Accessed Area Inspection Activities program identified comparable adverse environments that led to significant external corrosion. Also provide information regarding the need to continue the ongoing condition monitoring activities for pipe 18-CC-235-121 into the subsequent period of extended operation, such that a specific aging management review item would be needed to capture this activity in an aging management program.

Dominion Response:

Actions Taken to Address Adverse External Environmental Conditions

Sections of blowdown and chilled water system piping in Turbine Building to Auxiliary Building pipe tunnel have been re-routed to allow easier personnel access to the tunnel. Following re-routing of the piping, moisture and debris were removed from the tunnel. Pipe 18-CC-229-121, one of two pipes noted with significant external corrosion, has been replaced. Additionally, a new sump pump has been installed in the Turbine Building to Auxiliary Building pipe tunnel sump. These corrective actions have been effective in improving the Turbine Building to Auxiliary Building pipe tunnel access and environment. Dry, non-aggressive environmental conditions in the Turbine Building to Auxiliary Building pipe tunnel have been noted in walkdowns of the tunnel over the last several years.

Other Activities From the Infrequently Accessed Area Inspection Program

The one-time inspections of the other infrequently accessed areas have been completed, as documented in the UFSAR, Table 18-1, item number 9. The only area that required follow-up inspections was the Turbine Building to Auxiliary Building tunnel. No other inspections specified by the Infrequently Accessed Area Inspection Activities have identified comparable adverse environments that led to external corrosion requiring corrective actions.

Ongoing Condition Monitoring Activities for Pipe 18-CC-235-121

Quarterly walkdowns are performed to verify the Turbine Building to Auxiliary Building pipe tunnel remains dry. Yearly wall thickness measurements are being performed on pipe 18-CC-235-121 to trend the degradation until it is replaced. Trending of the yearly data for each of the measurement locations indicates that wall thicknesses have remained consistent from 2014 to 2018. Isolation valves are planned to be installed during the fall 2019 outage that will facilitate replacement of pipe 18-CC-235-121 while the units are online. Pipe 18-CC-235-121 will be replaced prior to the subsequent

period of extended operation. As previously indicated, corrective actions taken to date have greatly improved the environmental conditions in the Turbine Building to Auxiliary Building pipe tunnel and have allowed access for periodic walkdowns and inspections. After replacement of pipe 18-CC-235-121, system engineer walkdowns will manage aging of the pipe external surfaces on a refueling outage frequency consistent with the *External Surfaces Monitoring of Mechanical Components* program (B2.1.23).

RAI B2.1.28-2

Background:

GALL-SLR AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," provides recommendations, in part, for managing the aging effects of the underlying metallic pressure boundary material due to the loss of coating integrity. SLRA Section B2.1.11, "Open-Cycle Cooling Water System," states that the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program in Section B2.1.28 "will manage the aging effects of internal surface coatings including those of metallic surfaces coated with Carbon Fiber Reinforced Polymer [CFRP] that is used as a pressure boundary." SLRA Section B2.1.28 states that after enhancements, the program will be consistent with GALL-SLR AMP XI.M42. Regarding the CFRP lining, relief request (ADAMS Accession No. ML16355A347 (proprietary)) associated with installation of the CFRP repair includes a reference to an American Society of Mechanical Engineers (ASME) Code Case "Repair of Class 2 and 3 Piping by Carbon Fiber Reinforced Polymer Composite," and notes that it was "in development." The relief request also discusses the project team associated with the CFRP system application and identifies multiple team members who were "active members on the ASME Task Group developing the Code Case for Repair of Class 2 and 3 Piping by CFRP Composite." The NRC's associated Safety Evaluation (ADAMS Accession No. ML17303A037 (proprietary)) clarifies that although, at that time, there were no available standards for CFRP repair of pipe, ASME Code Case N-871, "Repair of Buried Class 2 and 3 Piping Using Carbon Fiber Reinforced Polymer Composite," was under development. The staff notes that according to the NRC's above cited safety evaluation, the CFRP piping will be inspected over its service life in accordance with station procedures in compliance with Generic Letter (GL) 89-13, "Service Water System Problems Affecting Safety-Related Components," to ensure the condition of the piping system is suitable for continued service.

Issue:

SLRA Section B2.1.28, which credits the use of GALL-SLR AMP XI.M42 to manage the effects of aging for CFRP material that functions as the pressure boundary, appears to be beyond the conditions and operating experience of those for which the GALL-SLR AMP XI.M42 was evaluated. The staff notes that, since the submittal of the relief request discussed above, the ASME code committees have approved Code Case N-871. If the requested relief for installation of the CFRP at Surry had occurred today, then the staff would consider the specific inservice inspection (ISI) requirements given in ASME Code Case N-871 as providing adequate actions for managing the effects of aging of CFRP during the subsequent period of extended operation. However, an alternate industry consensus document, other that ASME Code Case N-871, could be considered if appropriate technical bases are provided. In addition, based on the loads for which the CFRP system was designed, portions of the 30-inch and 36-inch piping encased in concrete appear to be credited for continuing to provide anchorage to portions of the piping routed above ground. Consequently, information regarding the following staff observations is needed for the staff to complete its review:

1. *The acceptance criteria specified in the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program do not appear to be consistent with the acceptance criteria specified in Code Case N-871 for similar post-installation indications identified in the CFRP lining.*
2. *The corrective actions specified in the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program, including potential alternative actions which allow return-to-service, do not appear to be consistent with the corrective actions specified in Code Case N-871 for similar post-installation defects identified in the CFRP lining.*
3. *The periodic visual inspections of the CFRP, conducted either through the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program or Generic Letter 89-13, do not appear to be consistent with the ISI visual examinations specified in Code Case N-871, regarding the type, extent, and frequency.*
4. *The training and qualification for individuals involved in coating/lining inspections specified in the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program do not appear to be consistent with the corresponding training and qualification requirements given in Code Case N-871, for personnel performing visual examinations and acoustic tap examinations.*
5. *The optional adhesion testing discussed in the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program does not appear to be consistent with the Mandatory Appendix VI "Acoustic Tap Examination"*

specified in Code Case N-871, Mandatory Appendix V, "Inservice Inspection," for the accessible surfaces of the CFRP at each terminal end.

6. *The relief request for the CFRP repairs states that the design objective of the CFRP system is to provide the necessary strength to carry all design loads "even if the host steel pipes continue to degrade." However, piping anchor loads from the attached 30-inch and 36-inch piping do not appear to have been included in the CFRP system design. Consequently, some portions of the 30-inch and 36-inch piping encased in concrete appear to be credited for continuing to provide anchorage to portions of the piping routed above ground, during the period of extended operation. Crediting portions of the piping encased in concrete as providing structural support does not appear to be consistent with the design objective of the CFRP system. In addition, existing aging management activities do not address how the continued degradation of the piping encased in concrete, which is being credited as an anchor, will ensure the structural capacity of the host steel piping will be maintained during the subsequent period of extended operation.*

Request:

1. *Provide the technical bases for applying the acceptance criteria, regarding the acceptability of blistering, cracking, and flaking, specified in the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program that do not appear to be comparable to the acceptance criteria specified in Code Case N-871 for similar degradation (i.e., blistering, cracking and flaking).*
2. *Provide the technical bases for applying the corrective actions, regarding return to service of coatings with indications of peeling and delamination, specified in the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program that do not appear to be comparable to the corrective actions specified in Code Case N-871 for similar degradation.*
3. *Provide information to show that the periodic visual inspections of the CFRP will be performed to comparable standards as the visual inspections specified in Code Case N-871, Mandatory Appendix V, "Inservice Examination" for visual inspections.*
4. *Provide information to show that personnel performing visual inspections or other inspections specified in the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program will be qualified equivalent to the provisions of Code Case N-871, Subarticle 5400, "Qualification of Examination and QC Inspection Personnel."*
5. *Provide technical bases to show that the minimum bond length at the terminal ends of the CFRP does not need to be periodically verified to ensure it remains bonded to*

the steel substrate equivalent to that specified in Code Case N-871, Mandatory Appendix VI, "Acoustic Tap Examination."

6. *For the portions of 30-inch and 36-inch pipes encased in concrete that are credited to function as anchors for the piping routed above ground, provide information to show that aging effects of the piping will be managed to ensure that the continued degradation of the piping has not caused the structural capacity of the host pipe to be exceeded. If the anchor points for the 30-inch and 36-inch piping routed above ground do not credit structural integrity of the piping encased in concrete, then provide the anchor loads induced by the piping routed above ground and show that the minimum bond lengths at the terminal ends are adequate to transfer these loads into the CFRP system.*

Dominion Response:

Prior to the subsequent period of extended operation, the 96-inch circulating water outlet piping will be lined with carbon fiber reinforced polymer (CFRP). Separate design changes will install CFRP in the 96-inch circulating water inlet piping and the 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. The CFRP design changes will be completed over the next several refueling outages. The CFRP lining will be used as the pressure boundary as approved by the NRC Safety Evaluation for relief from the ASME Code dated December 20, 2017 (ML17303A037 (proprietary)).

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 except those of metallic surfaces lined with CFRP that is used as a pressure boundary. After initial installation and an inspection period of four to six years following in-service operations, periodic visual inspections will be performed on 100% of the accessible CFRP lined surfaces on a ten year frequency consistent with ASME Code Case N-871 inspection requirements by the *Open-Cycle Cooling Water System* program (B2.1.11). Following submittal of the SLRA, the ASME code committees have approved ASME Code Case N-871.

Response to RAI B2.1.28-2, Request 1:

Program procedures will be revised to include the following CFRP defect inspection acceptance criteria for aging effects associated with air voids, bubbles, blisters, delaminations, and other defects (such as cracking and crazing). Inspections for foreign matter shall be performed consistent with *Open-Cycle Cooling Water* program (B2.1.11) flow blockage aging management requirements.

Air Voids (ASME Code Case N-871 section 4390 (b)(1), 4390 (b)(2), and 4390 (d)):
For embedded air voids of area less than or equal to 25 square inches that have been visually detected in layers beneath the topcoat, they shall be repaired in accordance with the following requirements unless otherwise specified in the design documents.

(1) Except at terminal ends, embedded voids smaller than 2 inches square do not require corrective action provided total void area is less than 1% of the total laminate area and there are no more than 10 such voids per 10 feet square.
(2) At terminal ends, embedded voids with major dimension greater than 1 inch, and all other voids that may interfere with required examinations, shall be rejected and repaired. Total remaining void area shall be less than 0.5% of the total laminate area and there shall be no more than 5 voids per 10 feet square.

All other defects and all voids larger greater than 25 square inches shall be rejected, and a repair designed to maintain water tightness of the system.

Bubbles, blisters or other defects (ASME Code Case N-871 section 4390 (c)):
If bubbles or blisters with major dimension exceeding 1 inch are detected anywhere within the protective epoxy topcoat, they shall be removed and repaired in accordance with ASME Code Case N-871 Section 4380(d.

Delaminations or Voids (ASME Code Case N-871 section 5350 (a) and (b)):
Unless permitted by design documents, acceptance criteria for acoustic tap examination of terminal ends shall consider the following.

(1) Delaminations or voids detected as being within ½ inch of each other shall be considered as joined. Size and location of unacceptable delaminations or voids with major dimensions exceeding one inch shall be recorded prior to repair.
(2) Any void or delamination detected as being within ½ inch of each other can be accepted if a technical basis is documented and provided by the design engineer in the examination record.

Response to RAI B2.1.28-2, Request 2:

Program procedures will be revised to include the following defect repair criteria as part of the corrective actions:

For air void defects (ASME Code Case N-871 section 4390 (b)(3) and (b)(4)):

(1) Rejected embedded voids shall have holes drilled (maximum ¼ inch diameter) for filling and venting using a drill-stop to ensure additional layers beyond the

affected layer are not damaged and shall then be low-pressure injected with thickened epoxy.

(2) If drill holes for injection and venting encroach upon the water-tightness layer, they shall be covered after injection with two layers of bidirectional CFRP centered over the drill holes. The first layer shall be installed at 0 degree / 90 degree orientation to the pipe axis and shall cover a minimum of 6 inches on all sides of the drilled holes; the second layer shall be installed at ±45 degrees orientation to the pipe axis and cover all edges of the first layer. Compared to internal coating corrective actions, lining voids or delaminations exceeding acceptance criteria flaw dimensions noted in response #1 noted above require repair. Any void or delamination detected as being within ½ inch of each other can be accepted if a technical basis is documented and provided by the design engineer in the examination record.

For bubbles, blisters or other surface defects (ASME Code Case N-871 section 4380(d)):

(1) Bubbles or blisters with major dimension exceeding one inch shall be removed and sanded, and the top coat material reapplied in accordance with the approved installation procedure. This corrective action for CFRP linings is comparable to peeling of coatings specified in the Internal Coating/Linings For In-Scope Piping, Piping Components, Heat Exchangers and Tanks program. Both corrective actions require removal and restoration of the defect.

For all other defects and all voids larger than 25 square inches, a repair shall be designed to maintain water-tightness of the system (ASME Code Case N-871 section 4390 (d)):

(1) If a patch repair is required it shall contain at least an equivalent number of layers that the defect penetrates. The area to be repaired shall be ground to remove all defects and tapered to the adjacent surface. Final grinding shall be done with a new disk to ensure a proper surface for bonding.
(2) Wet layup shall be used for patch repair.
(3) Patches shall extend beyond the defect area in accordance with the development length specified in the approved installation procedure or design drawings.
(4) Sides of the patches shall be tapered as specified in the design, not to exceed a slope of 1:5.

A final visual inspection shall be performed to verify the CFRP system has achieved the percentage of cure corresponding to achievement of required mechanical properties

before placing the repaired piping back in service. In no case shall the system be placed in service before achieving 85% cure.

Response to RAI B2.1.28-2, Request 3:

Program procedures will be revised to require accessible CFRP linings be 100% visually examined consistent with ASME Code Case N-871 section Appendix V-2100 during an inspection period between four and six years following return of the repaired area to service; and a minimum of once per 10 year inservice inspection interval thereafter in the same inspection period of each succeeding inspection interval. All areas previously documented shall be examined, measured, and compared with the previous inspection records. Any indications of flaw growth shall cause removal of the defective area and repair consistent with ASME Code Case N-871. Any new flawed areas shall be evaluated consistent with ASME Code Case N-871.

Response to RAI B2.1.28-2, Request 4:

Program procedures will be revised to require personnel who perform visual examinations and inspections of CFRP lined piping to be qualified VT-1 consistent with the requirements identified in IWA-2300 of ASME Code Section XI. Personnel who perform acoustic examinations of CFRP lined piping shall be qualified consistent with Mandatory Appendix VI of ASME Code Case N-871. In addition the following also applies for personnel performing visual examinations and QC inspections:

- Equivalent training as required for CFRP applicators as described in ASME Code Case N-871 Mandatory Appendix II on the mixing and application of carbon fiber composites and epoxies including a written exam.
- A minimum of 16 hours in-situ training and oversight by qualified inspection personnel with previous equivalent experience prior to performing examinations or inspections independently.
- All training shall be documented on a qualification record

Response to RAI B2.1.28-2, Request 5:

Program procedures will be revised to require accessible surfaces of the CFRP lining at each terminal end to be acoustically impact tap examined consistent with the following:

- After installation of the final layer, the CFRP lining at each terminal end shall be acoustic tap examined on all accessible surfaces – but not less than 90% of the total surface area by qualified personnel capable of detecting and sizing delaminations and voids in any composite or bonding layer with dimensions of 1 inch by 1 inch.

- Where exposed substrate pipe is accessible, the substrate beneath the CFRP laminate at terminal ends shall be ultrasonically (e.g., electromagnetic acoustic transducer (EMAT) technique) or electromagnetically measured to document steel substrate thickness and capable of detecting variation in thickness of the steel substrate wall thickness within .040 inch accuracy.

During periodic inspections, the expansion rings need not be removed for this examination provided examinations of adjacent surfaces do not indicate the presence of new unacceptable indications that could extend beneath the rings.

<u>Response to RAI B2.1.28-2, Request 6:</u>

The CFRP internal liner of the "Steel with internal lining" piping provides a pressure boundary. The application of the CFRP liner isolates the internal surface of the steel piping from the system fluid, and eliminates the corrosive environment for the internal surface of the steel piping. As described above, the *Open-Cycle Cooling Water System* (B2.1.11) program will manage aging of the internal surface of the "Steel with internal lining" service water and circulating water system piping. The external surface of the "Steel with internal lining" piping in indoor air is managed by the *External Surfaces Monitoring of Mechanical Components* program (B2.1.23). The external surface of the service water system "Steel with internal lining" piping embedded in concrete (that exits the building into soil and may be exposed to groundwater) is managed by the *Buried and Underground Piping and Tanks* program (B2.1. 27). The external surface of the circulating water system "Steel with internal lining" piping embedded in concrete (and not exposed to soil on either side) does not have aging effects requiring management. Management of the internal and external surfaces of the "Steel with internal lining" piping assembly (both steel and carbon fiber reinforced piping) ensures that the piping will remain structurally sound and able to carry the anchor forces applied to the external steel surface of the piping. The NRC Safety Evaluation for relief from the ASME Code, dated December 20, 2017, (ML17303A037 (proprietary)) determined that the CFRP system is designed to have the necessary strength, reliability, and durability to support the design loads without considering the host pipe. The Surry design is consistent with the general design requirements in ASME Code Case N-871 that indicate the host pipe shall not be credited for providing structural contribution except for specified thickness and lengths at end terminations.

<u>SLRA Changes</u>

SLRA Sections B2.1.11, B2.1.28, A1.11, 3.3.2.2.7, Table 3.3.2-4, Table 3.3.2-5, Table 3.3.1 and Table A4.0-1, Item #11 are supplemented, as shown in Enclosure 5, to include the changes described above.

<u>RAI B2.1.34-1</u>

<u>Background:</u>

Dominion addressed the age-related degradation of loss of material and change in material properties for wooden power poles by including a plant-specific enhancement to the "detection of aging effects" program element of the Structures Monitoring Program (SLRA Section B2.1.34) to ensure that wooden power poles are inspected on a 10-year frequency. By letter dated April 2, 2019, Dominion stated that this enhancement follows the EPRI 1010654, "Evaluation of Wood Pole Condition Assessment Tools," recommendations for inspection cycles as described in the "Wood Pole Assessment Practices" section. SRP-SLR Section A.1.2.3.4 recommends that the discussion for the "detection of aging effects" program element should provide, in part, justification, including codes and standards referenced, to demonstrate that the technique and frequency are adequate to detect the aging effects before a loss of intended function.

<u>Issue:</u>

The staff notes that the referenced EPRI document describes the ten- to fifteen-year inspection cycle as what is typically performed in North America, but it does not provide a technical bases or justification for the use of such reference as a standard. Thus, it is not clear how the vulnerability of poles to decay, based on the wooden pole locations, were considered for the proposed inspection frequency. Additional justification is needed to demonstrate the adequacy of the proposed 10-year inspection frequency for wooden poles to ensure that the aging effects can be detected before a loss of intended function.

<u>Request:</u>

Provide justification that would demonstrate, pursuant to 10 CFR 54.21(a)(3), that the proposed inspection frequency for wooden poles will be adequate to detect the associated aging effects before a loss of intended function.

<u>Dominion Response:</u>

There are fourteen wooden poles on the 34.5 kV recovery paths from the switchyard to reserve station service transformers A and B that are included in the scope of SLR. The wooden poles were manufactured in 1981 or later from southern pine and pressure treated with chromated copper arsenate (CCA).

The USDA Forest Service's Forest Products Laboratory established a study of wooden post durability in 1964. The study examined southern pine posts treated with several different preservatives, including CCA. The conditions at the study site, in southern

Mississippi (American Wood Protection Association Deterioration Zone 5), presented a severe decay and termite biodeterioration hazard; therefore, long-term durability at this location indicates the potential for similar or even greater durability at SPS (American Wood Protection Association Deterioration Zone 4). The condition of each wooden post was evaluated at 1- to 2-year intervals from 1965 to 1990, and again in 2014. At each inspection, the wooden posts were subjected to a load applied to the top of the wooden post and were classified as "passing" or "failing".

This fifty-year study of 125 CCA-treated southern pine posts resulted in no failures. Other studies also concluded that CCA-treated wooden posts are highly durable. There were no observed failures in another set of 91 CCA-treated southern pine wooden posts exposed for 35 years at the same location. In a study conducted near Petawawa, Ontario, no failures occurred after 57 years for CCA-treated southern pine wooden posts.

Considering the fifty-year durability evaluation of CCA-treated southern pine poles in a more severe environment, a 10-year inspection period, as reflected in the *Structures Monitoring* program (B2.1.34), for CCA treated southern pine poles at SPS is appropriate to provide reasonable assurance that aging will be managed so that the intended function of the wooden poles is maintained throughout the subsequent period of extended operation.

Enclosure 2

PROPRIETARY RESPONSE TO RAIs 4.7.3-7 and B2.1.6-2 SET 2 REGARDING SPS SLRA

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

Enclosure 3

NON-PROPRIETARY RESPONSE TO RAIs 4.7.3-7 and B2.1.6-2 SET 2 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 4.7.3-7 and B2.1.6-2 SET 2 REGARDING SPS SLRA

RAI 4.7.3-7

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 that the LBB analysis for 80 years of operation is documented in WCAP-15550, Revision 2. WCAP-15550, Revision 2 identifies three elbow locations (locations 3, 6 and 15) as critical locations in the LBB analysis.

Issue:

WCAP-15550, Revision 0 (August 2000) is the basis document for the 60-year LBB analysis of the Surry plant, as indicated in Section IV.1.B.vii.2 of the Surry power uprate application dated January 27, 2010. WCAP-15550, Revision 0 indicates that location 4 is one of the critical elbow locations for the 60-year LBB analysis. In contrast, WCAP-15550, Revision 2 indicates that location 3 is one of the critical elbow locations instead of location 4.

Request:

Provide the basis for the change to the critical elbow location from location 4 (WCAP-15550, Revision 0) to location 3 (WCAP-15550, Revision 2) to confirm that location 3 is the highest stressed elbow location for the hot leg.

Dominion Response:

The basis for determining the critical (governing locations) is provided in Section 5 of WCAP-15550, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Units 1 and 2 Nuclear Power Plants for the Subsequent License Renewal Program (80 Years) Leak-Before-Break Evaluation." The critical locations are determined based on the faulted stresses (Table 3-2 of WCAP-15550, Revision 0 and Revision 2) and the material properties. The change in the critical location in the different revisions of WCAP-15550 is due to the updates and refinements in the stresses (i.e. deadweight, thermal expansion, and safe shutdown earthquake seismic loadings) over time.

Since the elbows are made of cast materials, the critical location for the elbows in the hot leg in WCAP-15550, Revision 0, is based on the highest faulted stressed location (Table 3-2), which is at weld Location 4. In Revisions 1 and 2 of the WCAP-15550, the faulted stresses were higher at Location 3 (see Table 3-2); as a result, the critical

location was conservatively set to Location 3 for the hot leg. The changes to the faulted stresses for the LBB analysis are attributed to historical updates of the piping analysis model made after the publication of WCAP-15550, Revision 0.

[

]^{a,c,e} Revisions 1 and 2 of WCAP-15550 updated the LBB piping loads to account for all the above items.

As a result, the LBB stresses in Revisions 1 and 2 of WCAP-15550 are based on the most accurate and latest piping loads for deadweight, thermal expansion, and seismic. The updates to these loadings resulted in changes to the faulted stresses, which redefined the critical (governing) location for LBB in the hot leg from Location 4 (WCAP-15550, Revision 0) to Location 3 (WCAP-15550, Revisions 1 and 2). Regardless of when the piping loads were updated, there were always sufficient stability margins available for both elastic plastic fracture mechanics and limit loads results (see WCAP-15550, Table 7-1 and Table 7-2) at either Location 3 or Location 4. Thus, the LBB margins and conclusions for the main coolant loop at Units 1 and 2 were always maintained over the lifetime of the plant.

In conclusion, the change in the critical location in WCAP-15550 from Location 4 (WCAP-15550, Revision 0) to Location 3 (WCAP-15550, Revision 1 and Revision 2) is due to the updates and refinements in the deadweight, thermal expansion, and safe shutdown earthquake seismic loadings. The changes in the LBB loadings resulted from [

]^{a,c,e} to determine the LBB critical location (i.e. Location 3) in the hot leg piping.

<u>RAI B2.1.6-2</u>

<u>Background:</u>

CASS with greater than 20% ferrite is subject to a greater degree of thermal embrittlement and thus lower fracture toughness. The staff noted that the applicant is applying the limit load methodology modified with Z-factors. The staff requests that the applicant take into account the following items (i) and (ii), while addressing the applicability of the limit load methodology for CASS with greater than 20% ferrite.

Issue:

1. *On page 70, in Chapter 4 of NUREG/CR-4513, Revision 2, item (c) states that "For CASS materials, adequate toughness for the pipe to reach limit load after aging shall be demonstrated." The staff requests that the applicant demonstrate that after aging of CASS with greater than 20% ferrite will have adequate toughness such that limit load methodology is applicable. Confirm that the Z factor used for the limit load analysis will be conservative compared with a full elastic-plastic analysis.*

2. *The flowchart for evaluating austenitic piping in Figure C-4210-1 of Appendix C of Section XI of the ASME Code indicates that the evaluation criteria for CASS with delta ferrite content greater than 20% is "in the course of preparation." Furthermore, the acceptance criteria (Element 6) in XI.M12 of the GALL-SLR Report states that evaluation of CASS piping containing delta ferrite greater than 20% "must be approved by the NRC staff on a case-by-case basis." The staff noted that the applicant applied the Z-factor methodology for CASS piping with delta ferrite greater 20% in C-6000 of Appendix C of Section XI of the ASME Code, even though C-6000 can only be applied to wrought austenitic steels and CASS with less than 20% ferrite (per Figure C-4210-1).*

Request:

1. *Provide justification for the value of the Z factor in the limit load methodology and how that relates to the lower bound fracture toughness value in CASS piping/elbows at Surry Units 1 and 2.*

2. *The staff will be using the following documents to make a safety determination for the subject AMP. Therefore, the staff requests that the applicant submit these documents officially. The documents are: (1) WCAP-18258, Flaw Evaluation for Susceptible Reactor Coolant Loop Cast Austenitic Stainless Steel (CASS)," (2) "In-house audit response-NRC Audit for SPS'S SLR Information for TRP 12 CASS 3 4 19 Tomes."*

Dominion Response:

Dominion Response to RAI B2.1.6-2, Request 1:

The NRC provided guidance to the industry in a letter from Christopher I. Grimes to Douglas J. Walters, Nuclear Energy Institute, License Renewal Issue No. 98-0030, "Thermal Aging Embrittlement of Cast Stainless Steel Components," [ML003717179], May 19, 2000," and NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," Revision 2 for flaw tolerance evaluation for aging management of CASS piping components, which permitted the use of flaw evaluation procedures with Z-factors for SAW (submerged arc welds) currently in ASME Code, Section XI for application to cast

austenitic stainless steel (CASS) piping with delta ferrite content up to 25%. The aforementioned letter and NUREG-1801 specifically stated that:

> *Flaw tolerance evaluation for components with ferrite content up to 25% is performed according to the principles associated with ASME Code, Section XI, IWB-3640 procedures for SAWs, disregarding the ASME Code restriction of 20% ferrite. Extensive research data indicates that the lower-bound fracture toughness of thermally aged CASS materials with up to 25% ferrite is similar to that for SAWs with up to 20% ferrite (Lee, S., Kuo, P. T., Wichman, K., and Chopra, O., Flaw Evaluation of Thermally-Aged Cast Stainless Steel in Light-Water Reactor Applications, Int. J. Pres. Vessel and Piping, pp 37-44, 1997).*

For subsequent license renewal, guidance for CASS flaw tolerance evaluation in NUREG-2191, the methodology described above is still discussed for screening of thermal aging susceptibility based on delta ferrite. However, the discussion on flaw tolerance evaluation per ASME Code, Section XI is set to delta ferrite levels up to 20%. Therefore, the Staff is requesting clarification for the use of SAW Z-factors with limit load methodology based on Appendix C of ASME Code, Section XI for CASS piping components with delta ferrite larger than 20%.

The justification for the use of SAW Z-factor with the limit load methodology from ASME Code, Section XI, Appendix C, with delta ferrite levels greater than 20%, as performed in WCAP-18258-P, Revision 1, "Flaw Tolerance Evaluation for Susceptible Reactor Coolant Loop Cast Austenitic Stainless Steel Elbow Components for Surry Units 1 and 2," April 2019, can be made based on two different ASME Code approved guidance documents, Code Case N-838, "Flaw Tolerance Evaluation of Cast Austenitic Stainless Steel Piping," August 3, 2015, and the 2019 ASME Code, Section XI updates (ASME Boiler and Pressure Vessel Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," 2019 Edition, Expected publication July 1, 2019; ASME Codes and Standards (C&S Connect), Record# 16-2757, "Code Change (in the WGPFE) for Flaw Evaluation of CASS Piping," Record Established: 11/09/2016, Project Manager: Timothy Griesbach. ASME Working Group on Pipe Flaw Evaluation; and Proceedings of the ASME 2017 Pressure Vessels and Piping Conference, PVP2017-66100, "Technical Basis for Flaw Acceptance Criteria for Cast Austenitic Stainless Steel Piping," July 16-20, 2017. Authors: D.J. Shim, N.G. Cofie, D. Dedhia, D. O. Harris, T.J. Griesbach, K. Amberge). These ASME Code approved guidance documents, which have also been reviewed by the NRC Staff, are discussed below.

ASME Code, Section XI - Code Case N-838

The first ASME Code approved guidance for flaw tolerance evaluation of CASS piping components with delta ferrite greater than 20% for use with license renewal commitments is in Code Case N-838. Code Case N-838 has been approved by the Staff in the Federal Register, "Approval of ASME Code Cases," Volume 83, No. 159, August 16, 2018. The Federal Register is out for public comments as proposed rules for ASME Code Cases, which will be incorporated into Regulatory Guide 1.147, "Inservice Inspection Code Case Acceptability, ASME Code, Section XI, Division 1," Proposed Revision 19 (DG–1342) (ML Accession No. ML18114A225). The NRC Rulemaking for Regulatory Guide 1.147, Revision 19 is targeted for November 2019. The NRC condition for Code Case N-838 in Federal Register, Volume 83, No. 159, and Regulatory Guide 1.147 is that the flaw tolerance guidance be used for CASS components with delta ferrite no greater than 25%. [ ][a,c,e]

The main purpose of Code Case N-838 is to help utilities perform flaw tolerance evaluation for CASS components with delta ferrite greater than 20%, knowing that the 2017 Edition of ASME Code, Section XI, Appendix C (Figure C-4210-1) flaw evaluation guidance is limited to CASS materials with delta ferrite up to 20%. Code Case N-838 methodology is applicable to Class 1 and 2 piping components operating between 500°F to 662°F for SA-351 static or centrifugal components composed of Grades CF3, CF3A, CF3M, CF8, CF8A and CF8M with delta ferrite values exceeding 20%. [ ][a,c,e] Per Code Case N-838, the delta ferrite is calculated per the Hull's equivalent factors. WCAP-18258-P calculates the delta ferrite for Surry specific elbows per the Hull's equivalent factors, as well, based on NUREG/CR-4513, Revision 2. The flaw tolerance guidance in Code Case N-838 is to postulate an axial and circumferential surface flaw with size of one-quarter thickness (1/4T) with a length 6 times its depth. Per the code case, it should be demonstrated that the final flaw size after crack growth for the above mentioned postulated flaw size should be less than maximum tolerable flaw depths shown in the Code Case N-838 tables.

Therefore, a flaw tolerance evaluation based on Code Case N-838 was performed as a supplement to the evaluation in WCAP-18258-P to demonstrate that for subsequent license renewal application, [ ][a,c,e] therefore, the flaw evaluation per Code Case N-838 is performed for only those susceptible locations.

As part of the Code Case N-838 evaluation, a 1/4T surface flaw with aspect ratio (AR = flaw length / flaw depth) of 6:1, oriented in both the axial and circumferential direction was postulated at the welds adjacent to the CASS elbows. A fatigue crack growth analysis is performed to determine the final flaw size (a_f/t) after 80 years of growth. The final flaw size was compared to the maximum tolerable flaw depths determined in Code Case N-838 Tables 1, 2 and 3 for a postulated circumferential flaw and Table 4 for a postulated axial flaw. The final flaw size after 80 years of growth remains below the maximum tolerable flaw size in Tables 1 through 4 of Code Case N-838. The flaw tolerance results for Surry based on the guidance of the Code Case N-838 are shown in Table 1 below. Therefore, the Surry CASS piping with delta ferrite greater than 20% have shown flaw tolerance for the subsequent license renewal period based on an ASME approved Code Case N-838. It is our understanding that this code case has been reviewed and will be approved shortly by the NRC Staff before the end of 2019.

Table 1: Flaw Tolerance Evaluation per Code Case N-838 for Axial and Circumferential Postulated Flaws at Surry Unit 1 Hot and Crossover Leg

a,c,e

2019 ASME Code, Section XI Updates for Appendix C

The justification for the use of SAW Z-factor with the limit load methodology from ASME Code, Section XI, Appendix C for CASS piping components with delta ferrite levels greater than 20% (as performed in WCAP-18258-P) can be made based on the 2019 Edition ASME Code, Section XI updates.

There are no flaw evaluation guidelines for CASS piping with delta ferrite content equal to or greater than 20% (as shown in Figure C-4210-1 of Appendix C) up to the current 2017 Edition of ASME Code, Section XI Appendix C. Over the last three years, the ASME Code Working Group on Pipe Flaw Evaluation had been developing a basis to update Appendix C and Figure C-4210-1 to provide guidance for CASS materials with different levels of delta ferrite content. The 2019 Edition of the ASME Code, which is scheduled to be published in July 2019, has updated Appendix C and Figure C-4210-1 (see Figure 1 herein) for use of limit load with SAW Z-factors for delta ferrite levels greater than 14% but less than or equal to 25%. For ferrite levels below 14%, limit load is sufficient with no use of Z-factors, while for ferrite levels greater than 25%, the flaw

acceptance criteria for ferritic steel Category 2 welds as provided in Appendix C-6000 can be used.

The background technical basis for the updates to Appendix C in the 2019 Edition of Section XI for CASS piping flaw evaluation as related to delta ferrite content is provided in ASME C & S Connect Record #16-2757 and ASME PVP2017-66100. The technical changes to the 2019 Edition of Section XI Appendix C were developed in the ASME Working Group on Pipe Flaw Evaluation. Throughout the ASME review process, several NRC staff members have provided comments and suggestions to improve the technical basis of the Appendix C changes. The technical changes to the 2019 Edition of Section XI passed through the ASME Board without any negative votes, which included voting by NRC Staff members who are on the Section XI Standards Committee. Thus, a detailed review of the changes to 2019 Edition of ASME Code, Section XI, Appendix C was performed by the NRC; as a result, the use of SAW Z-factors with limit load methodology for CASS material with delta ferrite between 14% and 25% is an acceptable methodology.

Based on PVP2017-66100, which forms the technical basis for the 2019 Edition of ASME Section XI Appendix C changes, two data plots can be used to the summarize the background of the methodology updates. Figures 10 and 11 from PVP2017-66100 (shown in Figure 2 herein) compares the normalized Z-factor to flow strength as a function of nominal pipe sizes for Grade CF8M and CF3/CF8 CASS materials. For the development of the technical basis in PVP2017-66100, normalized Z-factor is used because the experimental data had varying degrees of flow stress; therefore, a more accurate comparison of the normalized Z-factor is employed in the PVP paper. Also shown in Figures 10 and 11 of PVP2017-66100 are the Z-factors for wrought stainless steel (base metal), Submerged Arc Weld (SAW) / Shielded Metal Arc Weld (SMAW) and the ferritic steel Category 2 piping material in ASME Code, Section XI.

Based on Figure 10 of PVP2017-66100 for Grade CF8M, it is demonstrated that the normalized Z-factor for the two data points which falls between 0 and 14% ferrite content (Heat IDs AA1 and AA2, see PVP2017-66100) are very close to the wrought stainless steel, thereby confirming that Grade CF8M CASS in this delta ferrite content range can be treated as wrought stainless steel. The seven data points between 14% and 25% (Heat IDs D, Pipe, 74, 75C, 75T, 205 and 4133) all have normalized Z-factors that are less than the corresponding normalized Z-factors for the SAW/SMAW material, thereby justifying the conservative use of the Z-factor for the SAW/SMAW material for Grade CF8M CASS piping with delta ferrite content in the 14% to 25% range. It can also be seen that the remaining six data points (Heat IDs A, C, E, 1ELB, 2/3ELB and 3296) with delta ferrite contents greater than 25% have normalized Z-factors that are below

that of the ferritic Category 2 weld and hence the use of the ferritic Category 2 welds Z-factors for Grade CF8M CASS piping in this delta ferrite content range is conservative.

For Grades CF3/CF8, it can be seen from Figure 11 of PVP2017-66100 that normalized Z-factors for the two data points with ferrite content less than 14% (Heat P2 and F) are very close to that of the wrought base metal which indicates that delta ferrite content in this range can also be treated as the wrought base metal. All other heats with delta ferrite content greater than 14% have normalized Z-factors which are fairly above that for the wrought base metal but less than that for the SAW/SMAW and, as such, it is conservative to use the criteria for the SAW/SMAW presently in the ASME Code for these CASS Grades for delta ferrite content greater than 14%.

Therefore, the conclusion of PVP2017-66100, which was incorporated into the 2019 Edition of ASME Code, Section XI, Appendix C, was:

For Grade CF3/CF8 or equivalent CASS piping:

- For ferrite content ≤ 14%, use the flaw acceptance criteria for wrought stainless steel provided in ASME Code Section XI, Appendix C, Subsection C-5000 (limit load, with no Z-factors).
- For ferrite content > 14%, use the flaw acceptance criteria for SAW/SMAW stainless steel welds provided in ASME Code Section XI, Appendix C, Subsection C- 6000 (limit load with Z-factor per SAW/SMAW).

For Grade CF8M or equivalent CASS piping:

- For ferrite content ≤ 14%, use the flaw acceptance criteria for wrought stainless steel provided in ASME Code, Section XI, Appendix C, Subsection C-5000 (limit load, with no Z-factors).
- For 14% < ferrite content ≤ 25%, use the flaw acceptance criteria for SAW/SMAW stainless steel welds provided in ASME Code, Section XI, Appendix C, Subsection C- 6000 (limit load with Z-factor per SAW/SMAW).
- For ferrite content > 25%, use the flaw acceptance criteria for ferritic steel Category 2 welds provided in ASME Code, Section XI, Appendix C, Subsection C-6000 (limit load with Z-factors for ferritic steel Category 2 welds).

In conclusion, [

]^{a,c,e} the flaw evaluation per limit load methodology with Z-factors based on SAW per ASME Code, Section XI Appendix C is acceptable as the latest 2019 Edition has updated Figure C-4210-1 and the guidance for CASS piping with delta ferrite greater than 20%.

Thus, two separate ASME approved and NRC reviewed methodologies are provided (Code Case N-838 and 2019 Edition of ASME), which demonstrate acceptability of Units 1 and 2 CASS piping for those materials that have delta ferrite values larger than 20% [ ]^{a,c,e} As a result, the CASS piping/elbows in the main loop piping demonstrates sufficient fracture toughness and flaw tolerance for operation up to 80 years.

Figure 1: 2019 Edition ASME Section XI Figure C-4210-1

(19)

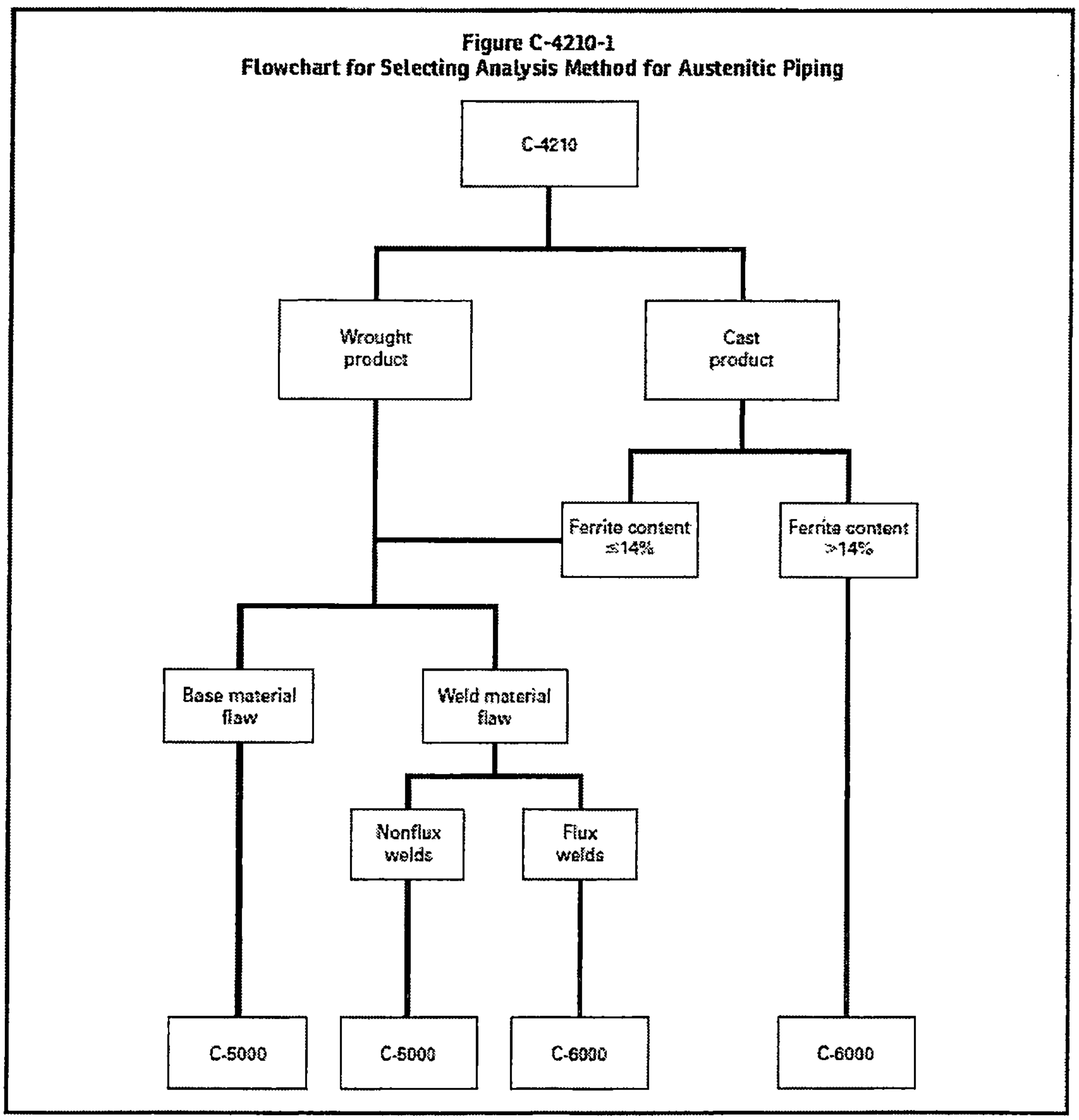

Figure 2: PVP2017-66100, Figures 10 and 11

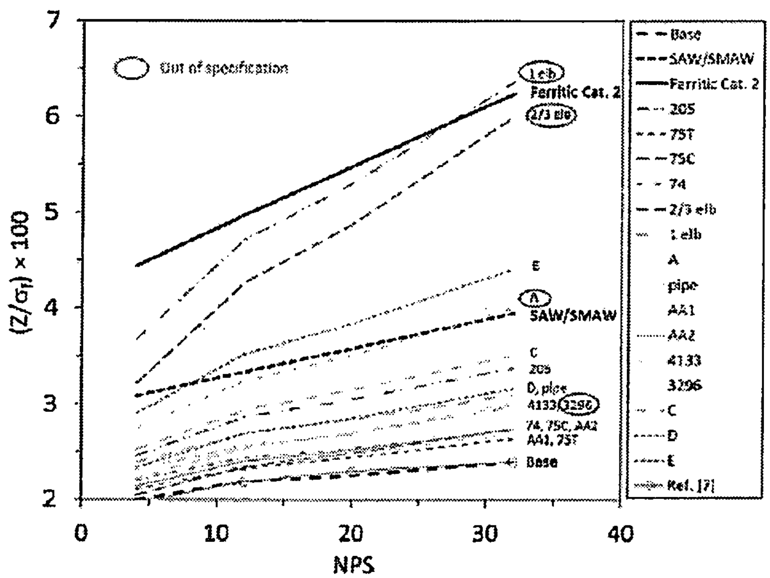

Figure 10 Normalized Z-factor versus nominal pipe size for Grade CF8M

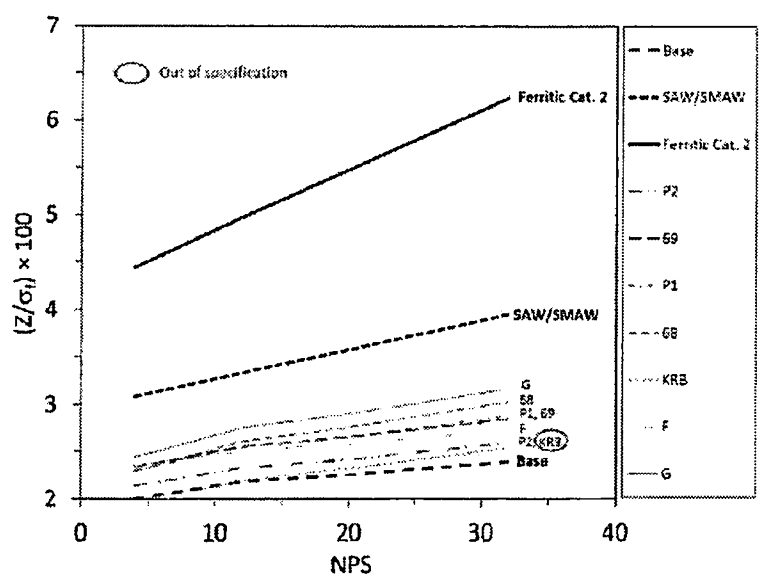

Figure 11 Normalized Z-factor versus nominal pipe size for Grades CF3 and CF8

Dominion Response to RAI B2.1.6-2, Request 2:

The text from "In-house audit response-NRC Audit for SPS's SLR Information for TRP 12 CASS 3 4 19 Tomes" is provided in Enclosure 6. Proprietary and Non-proprietary versions of WCAP-18258, "Flaw Tolerance Evaluation for Susceptible Reactor Coolant Loop Cast Austenitic Stainless Steel Elbow Components for Surry Units 1 and 2" are provided in Enclosures 7 and 8, respectively.

Enclosure 5

SLRA MARK-UPS –SET 2 RAIs

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

Table 2.3.3-29 Ventilation

Component Type	Intended Function(s)
Damper housing	Pressure Boundary, Structural Integrity (Attached)
Drip pan	Leakage Boundary (Spatial)
Ducting	Fire Barrier, Pressure Boundary, Structural Integrity (Attached)
Fan housing	Pressure Boundary, Structural Integrity (Attached)
Filter housing	Pressure Boundary, Structural Integrity (Attached)
Fire damper ~~(housing)~~assembly	Fire Barrier, Pressure Boundary
Flexible connection	Pressure Boundary
Flexible hose (Appendix R temporary ducting)	Pressure Boundary
Heat exchanger (central chilled water condenser - shell)	Leakage Boundary (Spatial)
Heat exchanger (central chilled water evaporator - shell)	Leakage Boundary (Spatial)
Heat exchanger (control room chilled water condenser - channel)	Pressure Boundary
Heat exchanger (control room chilled water condenser - shell)	Pressure Boundary
Heat exchanger (control room chilled water condenser - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (control room chilled water condenser - tubesheet)	Pressure Boundary
Heat exchanger (control room chilled water evaporator - channel)	Pressure Boundary

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

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-127	Steel (with stainless steel or nickel alloy cladding) steam generator heads and tubesheets exposed to reactor coolant	Loss of material due to boric acid corrosion	AMP XI.M2, Water Chemistry, and AMP XI.M19, Steam Generators	No	Consistent with NUREG-2191 with exceptions, and with a different program for some components. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program will manage loss of material of the steel with stainless steel cladding steam generator primary inlet and outlet nozzles exposed to reactor coolant.
3.1.1-128	Stainless steel, nickel alloy nozzles safe ends and welds: high pressure core spray; low pressure core spray; recirculating water, low pressure coolant injection or RHR injection mode exposed to reactor coolant	Cracking due to SCC, IGSCC	AMP XI.M7, BWR Stress Corrosion Cracking, and AMP XI.M2, Water Chemistry	No	Not applicable - BWR only.
3.1.1-129	Steel and stainless steel piping, piping components exposed to reactor coolant: welded connections between the re-routed control rod drive return line and the inlet piping system that delivers return line flow to the reactor pressure vessel exposed to reactor coolant	Cracking due to cyclic loading	AMP XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Not applicable - BWR only.
3.1.1-133	Steel components exposed to treated water	Long-term loss of material due to general corrosion	AMP XI.M32, One-Time Inspection	No	Not applicable - BWR only.

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

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Anti-vibration bar	SS	Nickel alloy	(E) Treated water >60°C (>140°F)	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-384	3.1.1-071	A
					Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	B
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-226	3.1.1-071	A
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	B
					Steam Generators (B2.1.10)	IV.D1.RP-225	3.1.1-076	A
Channel head (and cladding)	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Reactor coolant	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-232	3.1.1-033	E,4
					Water Chemistry (B2.1.2)	IV.D1.RP-232	3.1.1-033	D
				Cumulative fatigue damage	TLAA	IV.D1.R-221	3.1.1-008	A
				Loss of material	Steam Generators (B2.1.10)	IV.D1.R-436	3.1.1-127	A
					Water Chemistry (B2.1.2)	IV.D1.R-436	3.1.1-127	B
Channel head divider plate	FD	Nickel alloy	(E) Reactor coolant	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-367	3.1.1-025	A
					Water Chemistry (B2.1.2)	IV.D1.RP-367	3.1.1-025	B
				Cumulative fatigue damage	TLAA	IV.D1.R-221	3.1.1-008	C
Feedwater inlet nozzle	PB	Steel	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Treated water	Cumulative fatigue damage	TLAA	IV.D1.R-33	3.1.1-005	A
				Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-368	3.1.1-012	C
					Water Chemistry (B2.1.2)	IV.D1.RP-368	3.1.1-012	D
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	IV.D1.R-37	3.1.1-061	A
Feedwater inlet nozzle thermal sleeve	LTC	Stainless steel	(I) Treated water >60°C (>140°F)	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-384	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	D
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-226	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	D
					Steam Generators (B2.1.10)	IV.D1.RP-225	3.1.1-076	C

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

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Primary inlet nozzle and outlet nozzle (and cladding)	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-232	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.D1.RP-232	3.1.1-033	B
				Cumulative fatigue damage	TLAA	IV.D1.R-221	3.1.1-008	A
				<u>Loss of material</u>	<u>ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)</u>	<u>IV.D1.R-436</u>	<u>3.1.1-127</u>	<u>E:4</u>
					<u>Water Chemistry (B2.1.2)</u>	<u>IV.D1.R-436</u>	<u>3.1.1-127</u>	<u>D</u>
				~~Loss of material~~	~~Water Chemistry (B2.1.2)~~	~~IV.C2.RP-23~~	~~3.1.1-088~~	~~A~~
Primary inlet nozzle safe end and outlet nozzle safe end	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	3.1.1-136	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-232	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.D1.RP-232	3.1.1-033	B
				Cumulative fatigue damage	TLAA	IV.D1.R-221	3.1.1-008	A
Primary manway (includes pad and cladding)	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-232	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.D1.RP-232	3.1.1-033	B
				Cumulative fatigue damage	TLAA	IV.D1.R-221	3.1.1-008	A
				Loss of material	Steam Generators (B2.1.10)	IV.D1.R-436	3.1.1-127	A
					Water Chemistry (B2.1.2)	IV.D1.R-436	3.1.1-127	B

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

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
U-tube	HT;PB	Nickel alloy	(I) Reactor coolant	Cracking	Steam Generators (B2.1.10)	IV.D1.R-44	3.1.1-070	A
					Water Chemistry (B2.1.2)	IV.D1.R-44	3.1.1-070	B
				Cumulative fatigue damage	TLAA	IV.D1.R-46	3.1.1-002	A
			(E) Treated water >60°C (>140°F)	Cracking	Steam Generators (B2.1.10)	IV.D1.R-47	3.1.1-069	A
					Water Chemistry (B2.1.2)	IV.D1.R-47	3.1.1-069	B
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-233	3.1.1-077	A
					TLAA	IV.D1.RP-233	3.1.1-077	E, 1
				Reduction of heat transfer	Steam Generators (B2.1.10)	IV.D1.R-407	3.1.1-111	A
					Water Chemistry (B2.1.2)	IV.D1.R-407	3.1.1-111	B

Table 3.1.2-4 Plant-Specific Notes:

1. Wear of steam generator tubes at tube support plates is a plant-specific TLAA, evaluated in Section 4.7.8, Steam Generator Tube High Cycle Fatigue Evaluation.
2. ~~Not Used.~~The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program is used to manage loss of material for the primary inlet and outlet nozzles exposed to reactor coolant.
3. The One-Time Inspection (B2.1.20) program will verify the effectiveness of the Water Chemistry (B2.1.2) program to manage loss of material for the new transition cone closure weld.
4. The Steam Generators (B2.1.10) program will manage cracking of channel head (and cladding) exposed to reactor coolant.

[3.3.1-232] – Loss of material of insulated stainless steel components exposed to condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program. SPS has no in-scope insulated nickel alloy piping, piping components exposed to air-outdoor or condensation in the Auxiliary Systems. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable.

[3.3.1-241] – Loss of material of stainless steel or nickel alloy heat exchanger components exposed to air-indoor uncontrolled or condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. The internal surfaces of some components in the boron recovery system are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition.

[3.3.1-246] – SPS has no in-scope stainless steel or nickel alloy underground piping, piping components or tanks in the Auxiliary Systems.

3.3.2.2.5 Quality Assurance for Aging Management of Nonsafety-Related Components

Quality Assurance provisions applicable to subsequent license renewal are discussed in Appendix B1.3, Quality Assurance Program and Administrative Controls.

3.3.2.2.6 Ongoing Review of Operating Experience

The operating experience process and acceptance criteria are described in Appendix B1.4, Operating Experience.

3.3.2.2.7 Loss of Material Due to Recurring Internal Corrosion

Recurring internal corrosion can result in the need to augment AMPs beyond the recommendations in the GALL-SLR Report. During the search of plant specific OE conducted during the SLRA development, recurring internal corrosion can be identified by the number of occurrences of aging effects and the extent of degradation at each localized corrosion site. This further evaluation item is applicable if the search of plant specific OE reveals repetitive occurrences. The criteria for recurrence is: (a) a 10 year search of plant specific OE reveals the aging effect has occurred in three or more refueling outage cycles; or (b) a 5 year search of plant specific OE reveals the aging effect has occurred in two or more refueling outage cycles and resulted in the component either not meeting plant specific acceptance criteria or experiencing a reduction in wall thickness greater than 50 percent (regardless of the minimum wall thickness).

The GALL-SLR Report recommends that GALL-SLR Report AMP XI.M20, "Open Cycle Cooling Water System," GALL-SLR Report AMP XI.M27, "Fire Water System," or GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," be evaluated for inclusion of augmented requirements to ensure the adequate management of any recurring aging effect(s). Alternatively, a plant specific AMP may be proposed. Potential augmented requirements include: alternative examination methods (e.g., volumetric versus external visual), augmented inspections (e.g., a greater number of locations, additional locations based on risk insights based on susceptibility to aging effect and consequences of failure, a greater frequency of inspections), and additional trending parameters and decision points where increased inspections would be implemented.

The applicant states: (a) why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (b) the basis for the adequacy of augmented or lack of augmented inspections, (c) what parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (d) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (e) how leaks in any involved buried or underground components will be identified.

Plant specific OE examples should be evaluated to determine if the chosen AMP should be augmented even if the thresholds for significance of aging effect or frequency of occurrence of aging effect have not been exceeded. For example, during a 10 year search of plant specific OE, two instances of 360 degree 30 percent wall loss occurred at copper alloy to steel joints. Neither the significance of the aging effect nor the frequency of occurrence of aging effect threshold has been exceeded. Nevertheless, the OE should be evaluated to determine if the AMP that is proposed to manage the aging effect is sufficient (e.g., method of inspection, frequency of inspection, number of inspections) to provide reasonable assurance that the current licensing basis (CLB) intended functions of the component will be met throughout the subsequent period of extended operation. While recurring internal corrosion is not as likely in other environments as raw water and waste water (e.g., treated water), the aging effect should be addressed in a similar manner.

[3.3.1-127] – The review of plant-specific operating experience has identified recurring internal corrosion (RIC) in steel piping and components exposed to raw water in the service water system, circulating water system, component cooling system (cooling water interfaces), fire protection system, plumbing system, and ventilation system (cooling water interfaces). The programs noted below will manage RIC in the systems indicated.

Open-Cycle Cooling Water System program (B2.1.11)

As described below, SPS will implement the Open-Cycle Cooling Water System program (B2.1.11) to manage aspects of RIC in the service water system and 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 and 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 and fabricated of elastomer or polymer material or not subject to internal inspections within the scope of the program. In addition, the Appendix B operating experience section for the Open-Cycle Cooling Water System (B2.1.11) identifies corrective actions that have been taken, and additional actions that are scheduled, to minimize the likelihood of piping and component degradation due to RIC. Future occurrences of RIC in piping and components within the scope of the Open-Cycle Cooling Water System program (B2.1.11) will be documented in accordance with the Corrective Action Program. The Open-Cycle Cooling Water System program (B2.1.11) and associated enhancements are described in Appendix B.

a) *Why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function:*

Flow Blockage:

Flow blockage in open-cycle cooling water (OCCW) 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 as once every 4 hours and piping flush frequency increased to intervals as short as 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 biocide 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 license renewal; therefore, additional augmented inspections are not required.

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; therefore, additional augmented inspections are not required.

~~Loss of Material in Coated Steel Piping and Heat Exchanger Channel Heads~~Loss of Material and Loss of Coating Integrity in CFRP Lined Piping:

~~See the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program discussion in this further evaluation section for recurring internal corrosion details. Corrosion-resistant Carbon Fiber Reinforced Polymer (CFRP) liner has been installed on the component cooling water heat exchanger discharge piping and the main condenser discharge piping. 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 Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program will manage the aging of CFRP in the OCCW systems.~~Prior to the subsequent period of extended operation, the 96-inch circulating water outlet piping will be lined with carbon fiber reinforced polymer (CFRP). The CFRP lining will be used as the pressure boundary as approved by the NRC Safety Evaluation for relief from the ASME Code dated December 20, 2017 (ML17303A037 (proprietary)). The design changes for both units are in progress, and no documented aging effects for CFRP lined 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 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 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 (B2.1.28) program will manage the aging of the existing epoxy-coated steel piping.

b) *Basis for the adequacy of augmented or lack of augmented inspections:*

The frequency of strainer differential pressure monitoring and piping flushes is increased during times of elevated service water system temperature and vulnerability to flow blockage before loss of intended function. Additionally, biocide injection has significantly reduced biological fouling factors in the system.

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. The CFRP is not susceptible to pitting in a raw water environment as the existing steel pipe is. Inspections will be performed on 100% of the accessible CFRP lined surfaces on a ten year frequency consistent with ASME Code Case N-871 inspection requirements. Therefore, augmented inspections will not be necessary on piping lined with CFRP.

c) *What parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change):*

Trending is not required. The frequency of strainer differential pressure monitoring and piping flushes is increased during times of elevated service water system temperature and vulnerability to flow blockage before loss of intended function.

The condition of the internal CFRP lining in the circulating water and service water system will be assessed during scheduled inspections, and any degraded conditions recorded in the Corrective Action Program. The need for increased inspections will be evaluated as part of the corrective actions, considering past inspection results, extent of degradation, and rate of degradation.

d) *How inspections of components that are not easily accessed (i.e., buried, underground) will be conducted:*

Service water strainers are accessible for monitoring. In addition, affected piping flow paths are accessible for flushing.

Internal access is available to allow inspection of internal CFRP lined surfaces in the circulating water and service water system piping that are buried.

e) *How leaks in any involved buried or underground components will be identified:*

Strainers and associated flushing flow paths are not located in buried or underground environments.

Internal access is available to allow inspection of internal internal CFRP lined surfaces in the circulating water and service water system piping that are buried. Internal lining degradation and substrate metal degradation are identified with visual inspections.

Fire Water System program (B2.1.16)

As described below, SPS will implement the Fire Water System program (B2.1.16) to manage RIC in the fire protection system. In addition, the Appendix B operating experience section for the Fire Water System program (B2.1.16) identifies corrective actions have been taken, and additional actions that are scheduled, to minimize the likelihood of piping and component degradation due to RIC. Future occurrences of RIC in piping and components within the scope of the Fire Water System program (B2.1.16) will be documented in accordance with the Corrective Action Program. The Fire Water System program (B2.1.16) and associated enhancements are described in Appendix B.

a) *Why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function:*

Periodic fire protection system piping flushes, flow testing and proposed piping thickness measurements will be performed to identify pipe degradation prior to loss of system intended function. Periodic visual inspections and tank bottom thickness measurements are performed on the fire water storage tanks. In addition to recent piping replacements in the Turbine Building and the Auxiliary Building to address instances of RIC due to microbiologically-influenced corrosion, Low Frequency Electromagnetic Technique (LFET) or similar technique will be used for screening 100 feet of piping during each refueling cycle to detect changes in the wall thickness of the pipe. LFET screening or a similar technique will also be performed on accessible interior fire water storage tank bottoms during periodic inspections. Thinned areas found during the LFET scan are followed up with wall thickness examinations to ensure aging effects are managed and that wall thickness is within acceptable limits. In addition to the wall thickness examination, opportunistic visual inspections of the fire protection system will be performed whenever the fire water system is opened for maintenance.

b) *Basis for the adequacy of augmented or lack of augmented inspections:*

Currently performed flow testing and proposed thickness measurements will provide sufficient data for trending fire water system pipe or tank wall conditions prior to loss of intended function. Inspection samples for the 100 feet of piping will be selected from piping not previously replaced or inspected and determined to be potentially susceptible to RIC based on prior piping replacements or inspection results that require trending. Identified degraded pipe due to corrosion has been evaluated and replaced when necessary prior to loss of intended function. Other than proposed wall thickness measurements and opportunistic inspections, additional augmented inspections to detect RIC are not required.

c) *What parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change):*

Parameters trended during piping flushes include flow rates, pressure drops, calculated friction losses and/or signs of debris from corrosion. Parameters trended are pipe wall thickness measurements identified as a result of LFET results. When degraded conditions are identified, engineering evaluations are performed to determine the cause. If corrosion is identified, engineering evaluation will determine if additional inspections are required, the appropriate frequency of the inspection based on the projected corrosion rate, extent of condition for other areas in the system, and necessary repairs, if required.

d) *How inspections of components that are not easily accessed (i.e., buried, underground) will be conducted:*

Buried fire protection system piping is cast iron cement-lined pipe. In September 2014, a materials analysis was performed due to a failure initiated by a manufacturing defect in the cast iron portion of the buried fire main piping. The analysis found the balance of the cast iron cement-lined pipe to be in good condition with no significant loss of cement lining material, corrosion, cracking, fouling, or reduction of pipe interior diameter. Future inspections on underground fire main piping will be performed on an opportunistic basis when corrective maintenance work is performed on the fire water buried piping.

e) *How leaks in any involved buried or underground components will be identified:*

The water-based fire protection system is normally maintained at required operating pressure and is monitored such that loss of system pressure is detected and corrective actions initiated. A low pressure condition is alarmed in the control room by the auto start of the electric motor driven fire pump, followed by the start of the diesel-driven fire pump if the low pressure condition continues to exist. The status of the fire pumps is indicated in the control room and at the fire pump control panels in the pump house. Both fire pumps may be manually started from the control room. The combination of continuous monitoring of the fire protection system header pressure and the associated alarm with operator actions are sufficient activities for the identification of leaks in the fire protection system buried components.

<u>Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B2.1.25)</u>

As described below, SPS will implement the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B2.1.25) to manage RIC in portions of the plumbing system and unlined/uncoated portions of the service water system. In addition, the Appendix B operating experience section for the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B2.1.25) identifies corrective actions have been taken, and additional actions that are scheduled, to minimize the likelihood of piping and component degradation due to RIC. Future occurrences of RIC in piping and components within the scope of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B2.1.25) will be documented in accordance with the Corrective Action Program. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B2.1.25) and associated enhancements are described in Appendix B.

a) *Why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function:*

Sections of service water piping not within the scope of GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment," that have had documented leaks in the past due to corrosion of steel from a raw water environment have been replaced or repaired. Opportunistic inspections of susceptible piping and components will be performed when the system boundary is opened. Periodic system walkdowns in accordance with plant procedure will monitor for leakage.

Work orders have been created to replace affected portions of the plumbing system piping along an approximately 77 foot length in the Unit 1Turbine Building basement that have documented leaks from corrosion due to stagnant water in the lines.

b) *Basis for the adequacy of augmented or lack of augmented inspections:*

Service water piping not within the scope of GL 89-13 that has had documented leaks in the past is in lower pressure applications, such as vents and drains on gravity-fed heat exchangers. Opportunistic inspections of susceptible piping and components when the system boundary is opened, along with periodic system walkdowns are sufficient to detect aging effects. Piping sections that demonstrate significant aging effects in the inspections will be replaced.

The plumbing system piping that has documented leaks will be replaced, which obviates the need for augmented inspections. Opportunistic inspections of susceptible piping and components in other portions of the system within the scope of subsequent license renewal will continue to be performed when the system boundary is opened.

c) *What parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change):*

The condition of the service water piping not within the scope of GL 89-13 will be assessed during opportunistic inspections with occurrences of aging effects recorded in the Corrective Action Program. The need for increased inspections and repair or replacement will be evaluated as part of the corrective actions, considering the extent and rate of degradation.

The condition of the plumbing system piping will be assessed during opportunistic inspections following replacement with occurrences of aging effects recorded in the Corrective Action Program. The need for increased inspections and subsequent repair or replacement will be evaluated as part of the corrective actions, considering the extent and rate of degradation.

d) *How inspections of components that are not easily accessed (i.e., buried, underground) will be conducted:*

Service water piping not within the scope of GL 89-13 that has had documented leaks in the past is not located in buried or underground environments. The affected piping and other similar potentially susceptible service water piping not within the scope of GL 89-13 are in lower pressure applications such as vents and drains that are accessible for inspection.

The plumbing system piping that has had documented leakage in the past is not located in buried or underground environments. The affected piping is in the Unit 1 Turbine Building basement that is accessible for inspection.

e) *How leaks in any involved buried or underground components will be identified:*

Service water piping not within the scope of GL 89-13 that has had documented leaks in the past is not located in buried or underground environments. The affected piping and other similar potentially susceptible service water piping not within the scope of GL 89-13 are in lower pressure applications such as vents and drains, so that leaks can be identified with visual inspections.

The plumbing system piping that has had documented leakage in the past is not located in buried or underground environments. The affected piping is in the Unit 1 Turbine Building basement, so that leaks can be identified with visual inspections.

<u>Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program</u> (B2.1.28)

As described below, SPS will implement the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program (B2.1.28) to manage RIC <u>for internally coated components</u> in the circulating water and service water systems. In addition, the Appendix B operating experience section for the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program (B2.1.28) identifies corrective actions have been taken, and additional actions that are scheduled, to minimize the likelihood of piping and component degradation due to RIC. Future occurrences of RIC in piping and components within the scope of the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program (B2.1.28) will be documented in accordance with the Corrective Action Program. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program (B2.1.28) and associated enhancements are described in Appendix B.

a) *Why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function:*

~~Prior to the subsequent period of extended operation, the 96-inch circulating water outlet piping will be lined with carbon fiber reinforced polymer (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, <u>internal coating inspections of fifty-five, 1-foot length piping sections are performed every six years.</u>~~inspection is performed of approximately 25 percent of the circulating water and service water system internal coatings each refueling cycle, thereby 100 percent of all the circulating water and service water system piping is inspected every 6 years.~~

The component cooling heat exchanger channel heads are epoxy-coated steel exposed to raw water (service water). Inspections are performed yearly, which allows early detection of degradation of coatings and underlying metal.

b) *Basis for the adequacy of augmented or lack of augmented inspections:*

~~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. The CFRP is not susceptible to pitting in a raw water environment as the existing steel pipe is. 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, <u>internal coating inspections of fifty-five, 1-foot length piping sections are performed every six years.</u>~~inspection of approximately 25 percent of the circulating water and service water system internal coatings each refueling cycle provides an adequate sample size for detecting aging effects prior to loss of intended function. As a result of the inspection protocol with a 25 percent sample population, 100 percent of the circulating water and service water internal coatings is inspected every 6 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.

c) *What parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change):*

The condition of the internal coatings of the circulating water and service water system (including CFRP) will be assessed during scheduled inspections, and any degraded conditions recorded in the Corrective Action Program. The need for increased inspections will be evaluated as part of the corrective actions, considering past inspection results, extent of degradation, and rate of degradation.

Any degradation of the heat exchanger channel head coatings or metal is recorded in the Corrective Action Program. The need for increased inspections will be evaluated as part of the corrective actions, considering past inspection results, extent of degradation, and rate of degradation.

d) *How inspections of components that are not easily accessed (i.e., buried, underground) will be conducted:*

Internal access is available to allow inspection of accessible epoxy coated internal surfaces of ~~portions of the circulating water and~~ epoxy coated piping sections and service water system piping that are buried~~ and will be lined with CFRP~~.

Heat exchanger channel heads with coatings are not located in buried or underground environments. The interior surfaces of the epoxy coated piping sections and heat exchanger channel heads are accessible for inspection.

e) *How leaks in any involved buried or underground components will be identified:*

Internal access is available to allow inspection of accessible epoxy coated internal surfaces of ~~portions of the circulating water and~~ service water system piping that are buried~~ and will be lined with CFRP~~. Internal coating degradation and substrate metal degradation are identified with visual inspections.

Heat exchanger channel heads with coatings are not located in buried or underground environments. ~~H~~Epoxy coated piping sections and heat exchanger channel head leakage can be identified with visual inspections.

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 3.3.1 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
3.3.1-138	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, raw water (potable), treated water, treated borated water, fuel oil, lubricating oil, waste water	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage; loss of material or cracking for cementitious coatings/linings	AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	No	Consistent with NUREG-2191 with a different program for the fire protection and domestic water storage tanks, and for carbon fiber reinforced piping in the service water and circulating water systems. Loss of coating or lining integrity of the fire protection and domestic water storage tanks will be managed by the Fire Water System (B2.1.16) program. Loss of coating or lining integrity of service water and circulating water systems carbon fiber reinforced piping will be managed by the Open-Cycle Cooling Water System (B2.1.11) program. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B2.1.16) program implementation. In addition to Auxiliary Systems, components in the Reactor Vessel, Internals, And Reactor Coolant System (reactor coolant) and Steam and Power Conversion System (condensate polishing) are aligned to this item.
3.3.1-139	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, raw water (potable), treated water, treated borated water, fuel oil, lubricating oil, waste water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	No	Consistent with NUREG-2191 with a different program for the fire protection and domestic water storage tanks, and for carbon fiber reinforced piping in the service water and circulating water systems. Loss of material of the fire protection and domestic water storage tanks will be managed by the Fire Water System (B2.1.16) program. Loss of coating or lining integrity of service water and circulating water systems carbon fiber reinforced piping will be managed by the Open-Cycle Cooling Water System (B2.1.11) program. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B2.1.16) program implementation. In addition to Auxiliary Systems, components in the Reactor Vessel, Internals, And Reactor Coolant System (reactor coolant) and Steam and Power Conversion System (condensate polishing) are aligned to this item.

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

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB; FD	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) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Concrete	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A
			(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
				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, 4
						VII.C1.A-414	3.3.1-139	A
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	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)~~Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-416	3.3.1-138	~~A~~E, 9,10
				Loss of material	~~Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)~~Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-414	3.3.1-139	~~A~~E, 9,10
			(E) Concrete	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A
		Titanium	(E) Air – indoor uncontrolled	None	None	VII.J.AP-160	3.3.1-122	A
			(I) Raw water	Cracking; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.AP-161b	3.3.1-123	A, 2, 3
			(I) Treated water	Cracking (titanium only); reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-187	3.3.1-042	C, 7

Table 3.3.2-4 Plant-Specific Notes:

1. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for external surfaces or for strainer elements that are monitored for clogging.
2. For components not covered by NRC GL 89-13.
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. 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 program to manage recurring internal corrosion for internally-coated steel piping.
5. Internal and external environments are such that the external surface condition is representative of the internal surface condition.
6. 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 other materials.
7. Reduction of heat transfer is not applicable to components that do not have a heat transfer function.
8. Flow blockage is not applicable in treated water.
9. The Open-Cycle Cooling Water System (B2.1.11) program will manage aging effects for the internal surfaces of carbon fiber reinforced piping exposed to raw water.
10. The function of the buried (in soil) portion of the service water outlet piping from plant heat exchangers to the discharge tunnel is to deliver flow. The only applicable aging effects are internal loss of lining integrity and loss of material that could result in flow blockage, as piping integrity is not required.

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	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)~~<u>Open-Cycle Cooling Water System (B2.1.11)</u>	VII.C1.A-416	3.3.1-138	~~A~~<u>E, 10</u>
				Loss of material	~~Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)~~<u>Open-Cycle Cooling Water System (B2.1.11)</u>	VII.C1.A-414	3.3.1-139	~~A~~<u>E</u>, 2<u>, 10</u>
			<u>(E) Concrete</u>	<u>None</u>	<u>None</u>	<u>VII.J.AP-282</u>	<u>3.3.1-112</u>	<u>A</u>

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.

10. The Open-Cycle Cooling Water System (B2.1.11) program will manage aging effects for the internal surfaces of carbon fiber reinforced piping exposed to raw water.

Table 3.3.2-29 Auxiliary Systems - Ventilation - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Fire damper ~~(housing)~~ assembly	FB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material; cracking; hardening; loss of strength; shrinkage	Fire Protection (B2.1.15)	VII.G.A-789	3.3.1-255	A, 3
			(I) Air – indoor uncontrolled	Loss of material; cracking; hardening; loss of strength; shrinkage	Fire Protection (B2.1.15)	VII.G.A-789	3.3.1-255	A, 3
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Concrete	None	None	VII.J.AP-282	3.3.1-112	A
Flexible connection	PB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	C, 2
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	C, 2
Flexible hose (Appendix R temporary ducting)	PB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	C, 2
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	C, 2
Heat exchanger (central chilled water condenser - shell)	LB	Steel	(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 1

weight of the RPV is carried by the neutron shield tank, and no vertical loads are transferred to the concrete biological shield (CBS) wall. The inner shell of the neutron shield tank extends continuously past the bottom of the reactor vessel to the basemat, where the vertical loads are transferred directly. Overturning moments and horizontal forces are resisted by the CBS wall through a layer of grout, which fills the 2 inch gap between the neutron shield tank and the CBS wall.

The maximum temperature on both the inside and outside surfaces of the CBS wall is 125°F. The maximum water temperature of the neutron shield tank is 125°F. The maximum fluence at the ID of the RPV is 7.71 x 10^{19} n/cm^2 (E > 1.0 MeV), determined by extrapolating surveillance program calculations to 80 years (72 EFPY). The actual EFPY value for SPS Units 1 and 2 is 68 however 72 EFPY was used in the EPRI study discussed below.

Irradiation Damage of the Concrete Biological Shield

EPRI Report 3002013051, "Irradiation Damage of the Concrete Biological Shield that Utilizes a Neutron Shield Tank: Basis for Concrete Biological Shield Wall for Aging Management," addresses the effects of irradiation exposure and environmental temperature on the structural capability of the CBS wall at nuclear power plants with a neutron shield tank between the RPV and CBS wall. The specific example plant utilized for development of this report was SPS, with the modeling parameters such as neutron shield tank design configuration, operating temperatures, and RPV fluence levels described above. Therefore, the plant-specific values determined and conclusions reached for the example plant in the report are directly applicable to SPS. Using an evaluation period of 72 EFPY (80 years of operation), those values and conclusions are:

- The maximum neutron fluence at the CBS wall surface of 1.18 x 10^{13} n/cm^2 (E > 0.1 ~~1.0~~ MeV). This is substantially below the threshold value of 1.0 x 10^{19} n/cm^2 for E > 0.1 MeV.
- The estimated gamma surface dose at the CBS wall of 2.75 x 10^8 Rad is below the acceptability threshold of 1.0 x 10^{10} Rad.
- The maximum concrete temperature due to gamma heating is 125.1°F, which is approximately the same as the maximum ambient temperature of 125°F at the surface of the concrete and is below the acceptable long-term local temperature limit of 200°F for local areas.

In addition to the above conclusions, no plant-specific OE of concrete irradiation degradation has been identified. Therefore, no additional thermal and structural

analyses are required to establish the structural capability of the CBS wall, and no plant-specific aging management program to manage the effects of irradiation is required.

Irradiation of the Reactor Vessel Support Steel Assembly

In 1986, DOE, EPRI, WOG, and Virginia Power contracted Stone and Webster to develop Project Topical Report (PTR): "Reactor Vessel Support for Unit No 1 Surry Power Station, Life Extension Evaluation of the Reactor Vessel Support, including Appendix 3, Resistance to Brittle Fracture of the Neutron Shield Tank Materials," to address the concern of irradiated reactor vessel (RV) supports. The PTR specifically addressed the resistance to brittle fracture of the Surry Unit 1 RV support steel materials in the NST as a result of loss of fracture toughness due to neutron irradiation embrittlement in support of plants considering initial license renewal.

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The applied stresses for the area of the NST subject to high neutron fluence were developed in a separate calculation and compared to critical stresses derived from the fracture toughness evaluation to determine structural integrity of the Surry Unit 1 NST for 100 years of operation. A comparison of input parameters in the PTR including configuration, toughness, fluence, and EFPY was completed for SLR. The comparison and associated evaluation determined the following values and conclusions:

- The fluence to the NST shell at the RV sliding foot assembly is bounded by the fluence at the NST inner shell.
- The PTR was conservatively estimated for 100 years of plant operation (76.8 EFPY) that yields a fast neutron fluence (E>1Mev) of 9.5 x 10^{19} n/cm^2 at the inside surface of the RV and a fast neutron fluence (E>1Mev) of 5.0 x $10^{\cancel{19}}$ n/cm^2 at the outside surface of the RV.
- The fast neutron fluence (E>1Mev) on the ID of the NST for 100 years of plant operation is based upon 90% of the fluence on the outside diameter of the RV which is 4.5 x 10^{18} n/cm^2.
- The projected EFPY Value for SPS SLR is 68 EFPY which yields a fast neutron fluence (E>1Mev) of 3.42 x 10^{18} n/cm^2 at the inside surface of the NST.
- The maximum fracture toughness for 76.8 EFPY required to prevent propagation of a postulated surface flaw and postulated through wall crack was determined for the maximum design strength and design basis loading conditions.
- The peak stress values for the loads associated with the Surry Unit 1 NST were demonstrated to be below the critical stress for a through wall flaw and a surface flaw, thereby requiring no aging management.

An update was performed in support of subsequent license renewal using the PTR methodology. The updated evaluation validated the that Surry Unit 2 NST is similar

due to wear. Identification of deposits on the secondary-side of the steam generator, and the subsequent removal of sludge deposits help avoid tube degradation.

The Technical Specifications include the following requirements which are included in the *Steam Generators* program:

- Conducting condition monitoring assessments for each refueling outage during which steam generator tubes are inspected or plugged.
- Maintaining steam generator tube integrity by meeting performance criteria for tube structural integrity, accident-induced leakage, and operational leakage.
- Installing plugs in tubes found by inservice inspection to contain flaws that exceed acceptance criteria.
- Performing periodic inspections of steam generator tubes. Inspection scope, methods, and interval, ensure that tube integrity is maintained until the next planned inspection.
- Monitoring primary-to-secondary leakage.
- Monitoring secondary water chemistry to ensure controls are in place to inhibit steam generator tube degradation.

A1.11 OPEN-CYCLE COOLING WATER SYSTEM

The *Open Cycle Cooling Water System* program is an existing preventive, mitigative, condition monitoring, and performance monitoring program that manages loss of material, reduction of heat transfer, flow blockage, ~~and~~ cracking, and loss of coating or lining integrity, for the piping, piping components, and heat exchangers identified by the Dominion Energy responses to NRC Generic Letter (GL) 89-13, "Service Water System Problems Affecting Safety-Related Equipment." The program is comprised of the aging management aspects of the Virginia Electric and Power Company response to NRC GL 89-13 and includes: (a) surveillance and control to reduce the incidence of flow blockage problems as a result of biofouling, (b) tests to verify heat transfer of safety-related heat exchangers, (c) routine inspection and maintenance so that loss of material, corrosion, erosion, cracking, fouling, and biofouling cannot degrade the performance of systems serviced by the open-cycle cooling water system. This program includes enhancements to the guidance in NRC GL 89-13 that address operating experience such that aging effects are adequately managed.

System and component testing, visual inspections, nondestructive examination (i.e., ultrasonic testing and eddy current testing), and chemical injection are conducted to ensure that identified aging effects are managed such that system and component intended functions and integrity are maintained. Periodic heat transfer testing, visual inspection, and cleaning of safety-related heat exchangers with a heat transfer intended function is performed in accordance with the Virginia Electric and Power Company commitments to GL 89-13 to verify heat transfer capabilities.

The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (A1.28) will manage the aging effects of internal surface coatings ~~including~~except those of metallic surfaces ~~coated~~lined with Carbon Fiber Reinforced Polymer that is used as a pressure boundary.

A1.12 CLOSED TREATED WATER SYSTEMS

The *Closed Treated Water Systems* program is an existing program that manages loss of material, cracking, and reduction of heat transfer for components exposed to a closed treated water environment.

This is a mitigation program that also includes a condition monitoring program to verify the effectiveness of the mitigation activities. The program consists of: (a) water treatment, including the use of corrosion inhibitors, to modify the chemical composition of the water such that the effects of corrosion are minimized; (b) chemical testing of the water so that the water treatment program maintains the water chemistry within acceptable guidelines; and (c) inspections to determine the presence or extent of degradation. The program uses as applicable, EPRI Report 3002000590, "Closed Cooling Water Chemistry Guideline". Microbiological testing is performed as a diagnostic chemistry parameter for selected system water treatments.

A1.13 INSPECTION OF OVERHEAD HEAVY LOAD AND LIGHT LOAD (RELATED TO REFUELING) HANDLING SYSTEMS

The *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program is an existing condition monitoring program that manages cracking, loss of material due to corrosion and wear, and loss of preload on bolted connections for cranes and hoists within the scope of subsequent license renewal. The program includes periodic visual inspections to detect degradation of bridge, rail, and trolley structural components and indications of loss of preload on bolted connections. This program relies on the guidance in NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," ASME B30.2, "Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist)," ASME B30.11, "Monorail Systems and Underhung Cranes," and ASME B30.16, "Overhead Hoists (Underhung)."

For those cranes or hoists associated with Time-Limited Aging Analyses, the effects of past and future usage, including the number and magnitude of lifts, are evaluated in Section A3.7.1, Crane Load Cycle Limits.

A1.14 COMPRESSED AIR MONITORING

The *Compressed Air Monitoring* program is an existing preventive and condition monitoring program that manages loss of material. The *Compressed Air Monitoring* program includes

Table A4.0-1 Subsequent License Renewal Commitments

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

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
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~~30 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. (Revised - Set 2 RAIs) 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 provide guidance for internal inspection of carbon fiber reinforced polymer piping for aging effects such as voids, blistering, bubbles, cracking, crazing and delamination. (Added - Set 1 RAIs) 7. 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. 8. Procedures will be revised to require personnel who perform visual inspections and evaluation of carbon fiber reinforced polymer piping to be VT-1 qualified consistent with IWA-2300 of ASME Section XI and Mandatory Appendix II of ASME Code Case N-871. Personnel who perform acoustic examinations of CFRP lined piping will be qualified consistent with mandatory Appendix VI of ASME Code Case N-871. (Added - Set 1 RAIs) 9. Procedures will be revised to require installed CFRP linings be 100% visually examined in accordance with ASME Code Case N-871 section 5213 during an inspection period between four and six years following return of the repaired area to service; and a minimum of once per 10 year inservice inspection interval thereafter in the same inspection period of each succeeding inspection interval. (Added - Set 1 RAIs) 10. Procedures will be revised to require accessible surfaces of the CFRP linings at each terminal end to be acoustically impact tap examined in accordance with ASME Code Case N-871 section 5250(a) and 5250(c). The expansion rings need not be removed for this examination provided examinations of adjacent surfaces do not indicate the presence of new unacceptable indications that could extend beneath the rings. (Added - Set 1 RAIs)	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	11. 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) 12. 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. 13. 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. 14. Procedures will be revised to require all areas previously documented in accordance with ASME Code Case N-871 Section V-1100(b) shall be re-examined, measured, and compared with the previous inspection records. Any indications of flaw growth will be required to be repaired consistent with ASME Code Case N-871. Documentation of the repair, location and dimensions will be required. Any new flawed areas shall be evaluated consistent with ASME Code Case N-871. (Added - RAI Set 2) 15. Procedures will be revised to include verification that predicted wall thicknesses at the next scheduled inspection will be greater than the minimum wall thicknesses. 16. Procedures will be revised to include criteria for the extent and rate of on-going degradation that will prompt additional corrective actions. 17. 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. 18. Procedures will be revised to include the following CFRP defect inspection acceptance criteria for air voids, bubbles, blisters, delaminations and other defects (such as cracking and crazing): (Added - RAI Set 2) Air Voids For embedded air voids of area less than or equal to 25 square inches that have been visually detected in layers beneath the topcoat, they shall be repaired in accordance with ASME Code Case N-871 section 4390 (b)(1) and (b)(2) unless otherwise specified in the design documents. All other defects and all voids larger greater than 25 square inches shall be rejected, and a repair designed to maintain water tightness of the system. Bubbles, blisters or other defects If bubbles or blisters with major dimension exceeding 1 inch are detected anywhere within the protective epoxy topcoat, they shall be removed and repaired in accordance with ASME Code Case N-871 Section 4380(d). Delaminations or Voids Unless permitted by design documents, acceptance criteria for acoustic tap examination of terminal ends shall be consistent with ASME Code Case N-871 section 5350 (a) and (b)	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	19. Procedures will be revised to include the following defect repair criteria as part of the corrective actions.: (Added - RAI Set 2) For air void defects Repairs shall be consistent with ASME Code Case N-871 section 4390 (b)(3) and (b)(4) For bubbles, blisters or other surface defects Repairs shall be consistent with ASME Code Case N-871 section 4390 (d) For all other defects and all voids larger than 25 square inches A repair shall be designed to maintain water-tightness of the system consistent with ASME Code Case N-871 section 4390 (d) A final visual inspection shall be performed to verify the CFRP system has achieved the percentage of cure corresponding to achievement of required mechanical properties before placing the repaired piping back in service. In no case shall the system be placed in service before achieving 85% cure. 20. 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. 21. 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
13	*Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program	The *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to specify visual inspections for the effects of general corrosion, deformation, cracking, and wear on the rails in the rail system. 2. Procedures will be revised to specify visual inspections for general corrosion, deformation, cracking, wear and loose or missing fasteners and other conditions indicative of loss of bolting preload for the new fuel transfer elevator.	B2.1.13	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
14	*Compressed Air Monitoring* program	The *Compressed Air Monitoring* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to perform opportunistic visual inspections of internal surfaces of compressed air system components downstream of the dryers to verify the effectiveness of the compressed air system control of moisture (dewpoint) and particulate. Visual inspection results will be compared to previous results to ascertain if adverse long-term trends exist. Deficiencies will be documented in the Corrective Action Program and evaluations performed for test or inspection results that do not satisfy established criteria as defined in the applicable procedures.	B2.1.14	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
15	*Fire Protection* program	The *Fire Protection* program is an existing condition and performance monitoring program that ~~is credited~~will be enhanced as follows: 1. Procedures will be enhanced to require fire damper assemblies (rather than fire damper housings) to be visually inspected for loss of material and determined to be acceptable if there are no signs of degradation that could result in loss of fire protection capability due to loss of material. (Added - Set 2 RAIs) 2. Carbon dioxide and halon systems air flow testing procedures will be enhanced to trend air flow test data. In addition, procedures will be enhanced to specify that inspection results for the halon and CO2 systems meet the acceptance criteria if there are no indications of excessive loss of material. (Added - Set 2 RAIs) 3. Procedures will be revised to require an assessment for additional inspections to be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation. For sampling-based inspections, results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation. If degradation is detected within the inspection sample of penetration seals, the scope of the inspection is expanded to include additional seals in accordance with the plant's corrective action program. Additional inspections would be 20% of each applicable inspection sample; however, additional inspections would not exceed five. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the site's corrective action program. (Added - Set 2 RAIs)	B2.1.15	~~Ongoing~~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
17	*Outdoor and Large Atmospheric Metallic Storage Tanks* program	The *Outdoor and Large Atmospheric Metallic Storage Tanks* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to require periodic visual inspections of the refueling water storage tanks (RWSTs) be performed at each outage to confirm that the insulation caulking/sealant at the RWST concrete foundation is intact. The visual inspections of caulking/sealant will be supplemented with physical manipulation to detect any degradation. If there are any identified flaws, the caulking/sealant will be repaired or replaced and follow-up examination of the tank's surfaces conducted if deemed appropriate. An inspection of the caulk at the tank and concrete foundation interface will be included in the sample when the RWST external insulation is removed and sampled for external surface visual examinations. 2. Procedures will be revised to require visual and surface examination of the exterior surfaces of the RWSTs and CATs be performed to identify any loss of material or cracking. A minimum of either 25, one square foot sections or 20% of the surface area of insulation will be required to be removed to permit inspection of the exterior surface of each tank. The procedure will specify that sample inspection points be distributed in such a way that inspections occur near the bottoms, at points where structural supports, pipe, or instrument nozzles penetrate the insulation, and where water could collect such as on top of stiffening rings. If no unacceptable loss of material or cracking is observed, subsequent external surface examinations of insulated tanks will inspect for indications of damage to the jacketing, evidence of water intrusion through the insulation, or evidence of damage to the moisture barrier of tightly adhering insulation. 3. Procedures will be revised to require ECST weep holes be inspected for water leakage/condensation once each refueling cycle and corrective action taken if excessive leakage is observed. Accessible external metallic tank surfaces visible from inside the ECST piping penetration house will also require inspection once each refueling cycle as an indication of external ECST surface condition. Volumetric examination thickness measurements of the bottom of both ECMTs (100% of the surface exposed to soil) and both emergency condensate storage tanks will be performed and will occur during each 10-year period starting ten years before the subsequent period of extended operation. Results will be forwarded to engineering for evaluation and the need for additional inspections will be determined based on projected corrosion rates. One-time thickness measurements of a sample of the ECSTs vertical wall will be performed prior to the SPEO to assess potential degradation due to removable access plug leakage. The sample will examine the ECST vertical steel shell region between the three weep holes at the tank bottom associated with removable access plug leakage and vertically from that tank bottom junction to a distance of six feet along the vertical shell at the tank as a region potentially most susceptible to degradation. The inspection results will be projected to end of the SPEO to confirm the ECSTs intended functions will be maintained throughout the SPEO based on the projected rate of degradation. Any degradation not meeting acceptance criteria will require periodic 10-year thickness measurements and a sample expansion along the leakage path consistent with the observed degradation. (Added Set 2 RAIs) 4. Procedures will be revised to require volumetric examination thickness measurements of the bottom of both FWSTs and both RWSTs be performed each 10-year period during the subsequent period of extended operation starting ten years before the subsequent period of extended operation. Results will be forwarded to Engineering for evaluation and the need for additional inspections will be determined based on projected corrosion rates.	B2.1.17	Program will be implemented and inspections or tests begin 10 years before the subsequent period of extended operation. Inspections or tests that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
17	*Outdoor and Large Atmospheric Metallic Storage Tanks* program	5. For the carbon steel tanks (FWST, ECST, ECMT), procedures will be revised to provide non-ASME Code inspection guidance related to lighting, distance, offset, and surface conditions. The revised procedure will require the inspector confirm adequate lighting is available at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two feet or less is recommended. For distant surface inspections, viewing aids such as binoculars may be used. For internal inspections, accessible surfaces will be inspected. Cleaning will be performed as necessary to allow for a meaningful examination. If protective coatings are present, the condition of the coating will be noted. 6. A new procedure will be developed to specify that additional inspections be performed consistent with NUREG-2191. If any inspections do not meet the acceptance criteria, additional inspections are conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending). a. For inspections where only one tank of a material, environment, and aging effect was inspected, all tanks in that grouping are inspected. b. For other sampling based inspections there will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at the other unit. The additional inspections will be completed within the interval (i.e., 10-year inspection interval) in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the 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 any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the Corrective Action Program. However, for one-time inspections that do not meet acceptance criteria, inspections are subsequently conducted at least at 10-year inspection intervals.	B2.1.17	Program will be implemented and inspections or tests begin 10 years before the subsequent period of extended operation. Inspections or tests that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
34	*Structures Monitoring* program	The *Structures Monitoring* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to include inspection of the following structures that are within the scope of subsequent license renewal: decontamination building, radwaste facility, health physics yard office building, laundry facility, and machine shop. Inspections for the added structures will be performed under the enhanced program in order to establish quantitative baseline inspection data prior to the subsequent period of extended operation. (Revised - Change Notice 1) 2. Procedures will be revised to add the oiled-sand cushion to the inspection of the fire protection/domestic water tank foundation.(Added - Change Notice 3) 3. Procedures will be revised to include preventive actions to ensure bolting integrity for replacement and maintenance activities by specifying proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting. For structural bolting consisting of ASTM A325, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, "Specification for Structural Joints Using High-Strength Bolts," will be used. 4. The checklist for structural and support steel will be revised to indicate: "Are any connection members loose, missing or damaged (bolts, rivets, nuts, etc.)?". (Added - Change Notice 2) 5. ~~Procedures will be revised to require at least five years of experience (or ACI inspector certification) for concrete inspectors to be consistent with ACI 349.3R-002.~~ Procedures will be revised to require at least five years of experience (or ACI inspector certification) for concrete inspectors to be consistent with ACI 349.3R-002. Procedures will be revised to eliminate options for inspector qualifications that are not consistent with ACI 349.3R-002.(Revised - Change Notice 2) 6. ~~Procedures will be revised to inspect wooden power poles on a 10 year frequency.~~Procedures will be revised to specify that wooden pole inspections will be performed every ten years by an outside firm that provides wooden pole inspection services that are consistent with standard industry practice. Visual examinations may be augmented with soundings or other techniques appropriate for the type, condition, and treatment of the wooden poles, including borings to determine the location and extent of decay and excavation to determine the extent of decay at the groundline. (Revised - Change Notice 2) 7. Procedures will be revised to specify that evaluation of inspection results includes consideration of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. (Added - Change Notice 2) 8. Procedures will be enhanced to specify VT-1 inspections to identify cracking on stainless steel and aluminum components. A minimum of 25 inspections will be performed every ten years during the subsequent period of extended operation from each of the stainless steel and aluminum component populations assigned to the Structures Monitoring program. If the component is measured in linear feet, at least one foot will be inspected to qualify as an inspection. For other components, at least 20% of the surface area will be inspected to qualify as an inspection. The selection of components for inspection will consider the severity of the environment. For example, components potentially exposed to halides and moisture would be inspected, since those environmental factors can facilitate stress corrosion cracking. (Added - Change Notice 2)	B2.1.34	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
34	*Structures Monitoring* program	9. Procedures will be enhanced to specify that for the neutron shield tank (NST), loss of material due to corrosion, other than superficial corrosion, will be evaluated to ensure that the NST will continue to perform its intended functions, including structural support of the RPV. (Added - Set 2 RAIs) 10. Procedures will be enhanced to specify for the sampling-based inspections to detect cracking in stainless steel and aluminum components, additional inspections will be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement for all components constructed of the same material and exposed to the same environment. No fewer than five additional inspections for each inspection that did not meet acceptance criteria or 20 percent of each applicable material, environment, and aging effect combination will be inspected, whichever is less. Additional inspections will be completed within the 10-year inspection interval in which the original inspection was conducted. The responsible engineer will initiate condition reports to generate work orders to perform the additional inspections. The responsible engineer will evaluate the inspection results, and if the subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted. The responsible engineer will then determine the further extent of inspections. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies will be adjusted as determined by the Corrective Action Program. (Added - Change Notice 2) 11. Procedures will be enhanced to specify that evaluation of neutron shield tank findings consider its structural support function for the reactor pressure vessel. (Added - Change Notice 3) 12. Procedures will be enhanced to also include LOCAs as events that require evaluation for potentially degraded structures by Civil/Mechanical Design Engineering. (Added - Change Notice 3)	B2.1.34	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
35	*Inspection of Water Control Structures Associated with Nuclear Power Plants* program	The *Inspection of Water Control Structures Associated with Nuclear Power Plants* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to provide guidance for specification of bolting material, lubricants and sealants, and installation torque or tension to prevent degradation and assure structural bolting integrity. 2. Procedures will be revised to specify the preventive actions for storage discussed in Section 2 of Research Council for Structural Connections publication "Specification for Structural Joints Using ASTM A325 or A490 Bolts" for ASTM A325, ASTM F1852, ASTM F2280, and/or ASTM A490 structural bolts. 3. Procedures will be revised for concrete inspection to require at least five years of experience (or ACI inspector certification) to be consistent with ACI 349.3R-2002.	B2.1.35	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

B2 AGING MANAGEMENT PROGRAMS

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

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

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

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

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

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

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

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

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

B2.1.8 Flow-Accelerated Corrosion

Program Description

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

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

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

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

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

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

NUREG-2191 Consistency

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

Exception Summary

None

Enhancements

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

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

1. An engineering evaluation will be performed for systems that have been excluded from the FAC program due to no flow or infrequently used lines with a total operating and testing time that is less than 2% of the plant operating time. The purpose of the engineering evaluation is to confirm the scope of components that will qualify for the exclusion being extended into the subsequent period of extended operation. The engineering evaluation and modeling changes for the FAC program will be completed prior to entering the subsequent period of extended operation.

<u>Detection of Aging Effects (Element 4)</u>

2. Procedure will be revised to confirm that inspection scope expansions include the items noted below and to confirm that independent reviews of inspection scope expansions are independently reviewed by a qualified FAC engineer.
    - Any component within two pipe diameters downstream of the component displaying significant wear; or within two pipe diameters upstream if that component is an expander or expanding elbow.
    - The two most susceptible components from the CHECWORKS relative wear rate ranking in the same train containing the piping component displaying significant wear.
    - Corresponding components from other trains.
    - Inspections of additional components until no additional components with significant wear are detected.

Operating Experience Summary

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

FAC Operating Experience

1. In April 2009, FAC inspections were performed during the refueling outage using the ultrasonic testing technique. Those inspections found that two 1.5 inch nominal OD sections of piping in the main steam system had minimum wall thickness below 65% of nominal, and required replacement. That replacement effort was completed using FAC-resistant piping prior to resuming power operation. A review of the inspection history for the associated lines and for parallel trains was conducted, and a scope expansion of six extra main steam lines was identified. The completion of the follow-on scope expansion and evaluation demonstrated an ongoing focus within the *Flow-Accelerated Corrosion* program for susceptible components.
2. Industry Operating Experience: In August 2009, industry OE described a steam piping failure that caused a plant shutdown. A FAC review revealed a similar small-bore piping arrangement at Unit 2. No similar finding was identified for Unit 1. Accordingly, those pipe sections were replaced during the subsequent Unit 2 refueling outage.
3. In November 2009, as part of the *Flow-Accelerated Corrosion* program, an 18" diameter section of feedwater system piping was UT inspected and found to have inadequate wall thickness, thus requiring replacement during the current refueling outage. A work order was completed to replace the piping section using CrMo material prior to resuming power operation.

4. In November 2010, after a main steam trip valve was removed to allow replacement due to erosion at the lower gasket seat, Engineering performed a visual FAC inspection of the upstream and downstream components. Wall thinning was found on the downstream elbow. The three inch carbon steel elbow was replaced using CrMo material.
5. In April 2011, several components on a ten inch condensate polishing line were UT inspected during the refueling outage as part of the *Flow-Accelerated Corrosion* program. The measured wall thickness for a nozzle was projected to be below the minimum allowable wall thickness prior to the next refueling outage, thus requiring replacement or repair during the current outage. Weld buildup repairs were completed for the nozzle and associated elbow prior to resuming power operation.
6. In December 2015, an effectiveness review of the Flow Accelerated Corrosion Activity (UFSAR Section 18.2.16) was performed. The AMA was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. The results of that review indicated that license renewal references were not included in the Flow Accelerated Corrosion Activity procedures. Resolution was achieved by revising the controlling procedures for the Flow Accelerated Corrosion Activity to provide references to the technical reports or pertinent section of the license renewal application for the license renewal commitments.
7. In November 2016, a fleet self-assessment of the Flow Accelerated Corrosion Activity (UFSAR Section 18.2.16) was completed. The assessment included a review, with industry peers, of standard processes for the Flow Accelerated Corrosion Activity to identify whether they were as efficient and effective as possible. No Areas for Improvement were identified, but it was determined that efficiencies could be gained by implementing more modern technologies. Opportunities for procedure enhancements also were identified. Since 2016, FAC Manager software has been placed in service to automate the process of transferring component evaluation results into CHECWORKS-SFA™. Procedure enhancements continue to be processed.
8. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

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

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

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

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

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

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

<u>Erosion Operating Experience</u>

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

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

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

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

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

Conclusion

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

B2.1.11 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, and loss of coating or lining integrity 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 except those metallic surfaces lined with carbon fiber reinforced polymer (CFRP) that are

used as a pressure boundary. The CFRP lined components in the circulating water system and service water system piping will be inspected consistent with ASME Code Case N-871.

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~~30 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. (Revised - Set 2 RAIs)

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.

6. Procedures will be revised to provide guidance for internal inspection of carbon fiber reinforced polymer piping for aging effects such as voids, blistering, bubbles, cracking, crazing and delamination. (Added - Set 2 RAIs)

Detection of Aging Effects (Element 4)

7. 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.

8. Procedures will be revised to require personnel who perform visual inspections and evaluation of carbon fiber reinforced polymer piping to be VT-1 qualified consistent with IWA-2300 of ASME Section XI and Mandatory Appendix II of ASME Code Case N-871. Personnel who perform acoustic examinations of CFRP lined piping will be qualified consistent with mandatory Appendix VI of ASME Code Case N-871. (Added - Set 2 RAIs)

9. Procedures will be revised to require installed CFRP linings be 100% visually examined in accordance with ASME Code Case N-871 section 5213 during an inspection period between four and six years following return of the repaired area to service; and a minimum of once per 10 year inservice inspection interval thereafter in the same inspection period of each succeeding inspection interval. (Added - Set 2 RAIs)

10. Procedures will be revised to require accessible surfaces of the CFRP linings at each terminal end to be acoustically impact tap examined in accordance with ASME Code Case N-871 section 5250(a) and 5250(c). The expansion rings need not be removed for this examination

provided examinations of adjacent surfaces do not indicate the presence of new unacceptable indications that could extend beneath the rings. (Added - Set 2 RAIs)

11. 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)

Monitoring and Trending (Element 5)

12. 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.

13. 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.

14. Procedures will be revised to require all areas previously documented in accordance with ASME Code Case N-871 Section V-1100(b) shall be re-examined, measured, and compared with the previous inspection records. Any indications of flaw growth will be required to be repaired consistent with ASME Code Case N-871. Documentation of the repair, location and dimensions will be required. Any new flawed areas shall be evaluated consistent with ASME Code Case N-871. (Added - Set 2 RAIs)

Acceptance Criteria (Element 6)

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

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

17. 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.

18. Procedures will be revised to include the following CFRP defect inspection acceptance criteria for air voids, bubbles, blisters, delaminations and other defects (such as cracking and crazing): (Added - Set 2 RAIs)

    Air Voids

For embedded air voids of area less than or equal to 25 square inches that have been visually detected in layers beneath the topcoat, they shall be repaired in accordance with ASME Code Case N-871 section 4390 (b)(1) and (b)(2) unless otherwise specified in the design documents. All other defects and all voids larger greater than 25 square inches shall be rejected, and a repair designed to maintain water tightness of the system.

Bubbles, blisters or other defects

If bubbles or blisters with major dimension exceeding 1 inch are detected anywhere within the protective epoxy topcoat, they shall be removed and repaired in accordance with ASME Code Case N-871 Section 4380(d).

Delaminations or Voids

Unless permitted by design documents, acceptance criteria for acoustic tap examination of terminal ends shall be consistent with ASME Code Case N-871 section 5350 (a) and (b)

Corrective Actions (Element 7)

19. Procedures will be revised to include the following defect repair criteria as part of the corrective actions: (Added - Set 2 RAIs)

For air void defects

Repairs shall be consistent with ASME Code Case N-871 section 4390 (b)(3) and (b)(4)

For bubbles, blisters or other surface defects

Repairs shall be consistent with ASME Code Case N-871 section 4390 (d)

For all other defects and all voids larger than 25 square inches

A repair shall be designed to maintain water-tightness of the system consistent with ASME Code Case N-871 section 4390 (d)

A final visual inspection shall be performed to verify the CFRP system has achieved the percentage of cure corresponding to achievement of required mechanical properties before placing the repaired piping back in service. In no case shall the system be placed in service before achieving 85% cure.

20. 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.

21. 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 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 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.

7. 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.

8. 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.

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.

10. 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.

11. 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.
12. 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.
13. 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.
14. 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.

<u>Recurring Internal Corrosion</u> (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 and heat exchanger channel heads that has been ~~lined or~~ coated with epoxy coatings. 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.

B2.1.15 Fire Protection

Program Description

The *Fire Protection* program is an existing condition and performance monitoring program comprised of functional tests and visual inspections. The program manages:

- Loss of material for fire-rated doors, fire damper housings, the halon systems, RCP oil collection system, steel seismic gap covers and the low-pressure carbon dioxide systems
- Loss of material (spalling) or cracking for concrete structures, including fire barrier walls, ceilings, and floors
- Hardening, shrinkage, and loss of strength for elastomer fire barrier penetration seals and seismic gap elastomers
- Loss of material, change in material properties, cracking/delamination, and separation for non-elastomer fire barrier penetration seals, fire stops, fire wraps, and coatings cracking/delamination, and separation
- Loss of material and cracking for aluminum seismic gap covers

This program includes fire barrier inspections. The fire barrier inspection program requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, and floors, fire damper housings, and periodic visual inspection and functional tests of fire-rated doors to demonstrate that their operability is maintained. The program also includes periodic inspections and functional tests of the halon systems and low-pressure carbon dioxide systems.

The *Fire Protection* program requires visual inspections of not less than 20% of the penetration seals every 12 months, such that 100% of the seals are inspected every five years. The program specifies visual inspections of the fire barrier walls, ceilings and floors in structures within the scope of subsequent license renewal every five years. The visual inspections of fire barriers include determining the condition of fire wraps every eighteen months. The eighteen month frequency also is applicable for visual inspections of fire doors and damper assemblies. Periodic functional checks are performed on the fire doors.

The program will also provide for aging management of external surfaces of the halon systems and low-pressure carbon dioxide fire systems components that are within the scope of license renewal through periodic visual inspections for corrosion that may lead to loss of material. The program includes functional testing of the halon systems and low-pressure carbon dioxide fire suppression systems components in accordance with the Technical Requirements Manual.

Personnel performing inspections are qualified and trained to perform the inspection activities. Unacceptable conditions are entered into the Corrective Action Program for proper disposition.

NUREG-2191 Consistency

The *Fire Protection* program is an existing program ~~and is~~that, ~~-~~following enhancement, will be consistent with NUREG-2191, Section XI.M26, Fire Protection.

Exception Summary

None

Enhancements

~~None~~Prior to the subsequent period of extended operation, the following enhancement will be implemented in the following program elements:

Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), and Acceptance Criteria (Element 6)

1. Procedures will be enhanced to require fire damper assemblies (rather than fire damper housings) to be visually inspected for loss of material and determined to be acceptable if there are no signs of degradation that could result in loss of fire protection capability due to loss of material.

Monitoring and Trending (Element 5) and Acceptance Criteria (Element 6)

2. Carbon dioxide and halon systems air flow testing procedures will be enhanced to trend air flow test data. In addition, procedures will be enhanced to specify that inspection results for the halon and CO2 systems meet the acceptance criteria if there are no indications of excessive loss of material.

Monitoring and Trending (Element 5), Acceptance Criteria (Element 6), and Corrective Actions (Element 7)

3. Procedures will be revised to require an assessment for additional inspections to be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation. For sampling-based inspections, results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation. If degradation is detected within the inspection sample of penetration seals, the scope of the inspection is expanded to include additional seals in accordance with the plant's corrective action program. Additional inspections would be 20% of each applicable inspection sample; however, additional inspections would not exceed five. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the site's corrective action program.

Operating Experience Summary

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

1. In January 2010, an original K-10 mortar fire barrier in the Turbine Building/Auxiliary Building pipe tunnel was determined to be damaged and non-functional. The instance was corrected by providing a new installation of Rectorseal BIO K-10+ Fire Rated Mortar having a 3-hour rating, and providing the required train separation in accordance with 10 CFR 50, Appendix R, Section III.G.2(a).
2. In July 2012, during the performance of a periodic maintenance procedure for inspection (functional check) of a swinging safety-related special purpose fire door, the gum rubber seal on the latch side of the door frame was found to be deteriorated. The seal was replaced as determined by engineering evaluation.
3. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.
4. In January 2018, an aging management program effectiveness review was performed for the Fire Protection Program Activity (UFSAR Section 18.2.7). Information from the summary of that effectiveness review is provided below:

   The Fire Protection Program Activity is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. Key activities of the Fire Protection Program Activity that were reviewed include the inspection of fire doors, fire barriers, fire detection, fire suppression, fire protection system integrity, RCP oil collection system, and Appendix R equipment as well as the evaluation of inspection results, repairs/replacements, corrective actions, and AMA document updates. A review of Engineering inspection result reports from 2006 to 2017 confirmed inspections were conducted at appropriate intervals and corrective actions were taken consistent with the observed aging degradation. The review also included pertinent issues found in the Corrective

Action Program from 2006 through 2017 for age related degradation of fire protection components within the scope of license renewal.

Problems that included equipment obsolescence, false alarms, operator distraction, and potential single point failures were arising with the old fire detection system, which resulted in installation of a new fire detection system in 2015. Not all of the old fire panels were replaced. A new design change is currently being developed to address obsolescence of the remaining fire panels as well as make enhancements to the new fire detection system.

5. In March 2018, the NRC completed a triennial fire protection inspection. One finding was determined to have very low safety significance (Green). The finding involved failure to adequately protect fiberglass pipe that is susceptible to fire damage and required for safe shutdown. This finding was treated as a non-cited violation and closed. The subject pipe was replaced on both units with part fiberglass protected by Pyrocrete and part copper-nickel. Both portions of replacement pipe will withstand a three-hour fire.

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

Conclusion

The continued implementation of the *Fire Protection* 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.

B2.1.17 Outdoor and Large Atmospheric Metallic Storage Tanks

Program Description

The *Outdoor and Large Atmospheric Metallic Storage Tanks* program is an existing condition monitoring program that manages the effects of loss of material and cracking on the outside and inside surfaces of aboveground metallic tanks constructed on concrete or soil. This program manages aging effects associated with outdoor tanks with internal pressures approximating atmospheric pressure including the refueling water storage tanks (RWSTs), refueling water chemical addition tanks (CATs), emergency condensate storage tanks (ECSTs), and the emergency condensate makeup tanks (ECMTs). This program also manages aging of the fire protection/domestic water storage tanks (FWSTs) bottom surfaces exposed to soil.

The program includes preventive measures to mitigate corrosion by protecting the external surfaces of steel components per standard industry practice. The RWSTs are insulated and rest on a concrete foundation covered with an oil sand cushion. Caulking is used at the concrete-component interface of the RWSTs. The insulation of the RWSTs is corrugated aluminum with overlapped seams. The ECSTs and ECMTs are internally coated and protected by concrete missile barriers. Weep holes, located around the circumference of the ECSTs where the concrete missile shield meets the concrete foundation, allow drainage of leakage or condensation to the outside perimeter of the ECSTs. The weep holes will be inspected for water leakage once each refueling cycle. The CATs are skirt supported and insulated with sprayed-on rigid polyurethane foam.

The program manages loss of material on tank internal bare metal surfaces by conducting visual inspections. Surface exams of external tank surfaces are conducted to detect cracking on the stainless steel tanks. Inspections of RWST caulking are supplemented by physical manipulation. Thickness measurements of the tanks bottoms are conducted to ensure that design thickness and corrosion allowance criteria are met. A periodic sampling-based inspection is used on the external surfaces of insulated tanks. Inspections not conducted in accordance with ASME Code, Section XI requirements are conducted in accordance with plant-specific procedures, including inspection parameters such as lighting, distance, offset, and surface conditions. If any inspections do not meet the acceptance criteria, additional inspections are conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending); however:

- For inspections where only one tank of a material, environment, and aging effect was inspected, all tanks in that grouping are inspected.
- For other sampling based inspections there will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent

of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at the other unit.

The additional inspections will be completed within the interval (i.e., 10-year inspection interval) in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the 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 any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the Corrective Action Program. However, for one-time inspections that do not meet acceptance criteria, inspections are subsequently conducted at least at 10-year inspection intervals.

The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) manages the internally coated surfaces of the ECSTs and ECMTs. Internal surfaces of the RWSTs and CATs are managed by the *One-Time Inspection* program (B2.1.20). Tank reinforced concrete foundations and the reinforced concrete missile barrier of the ECSTs and ECMTs are managed by the *Structures Monitoring* program (B2.1.34).

NUREG-2191 Consistency

The *Outdoor and Large Atmospheric Metallic Storage Tanks* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks.

Exception Summary

The following program element(s) are affected:

Preventive Actions (Element 2), Parameters Monitored/Inspected (Element 3), Detection of Aging Effects (Element 4), Acceptance Criteria (Element 6), and Corrective Actions (Element 7)

1. NUREG-2191 specifies for outdoor tanks, that sealant or caulking is applied at the interface between the tank external surface and concrete or earthen surface to mitigate corrosion of the tank by minimizing the amount of water and moisture penetrating the interface. The ECSTs and ECMTs do not use caulking or sealant at the concrete-component interface and therefore, do not require inspection of the caulking or sealant. The RWST has sealant installed at the interface between the insulation jacketing and the tank concrete foundation.

Justification for Exception:

The ECSTs and ECMTs are insulated from the outside atmosphere by two inches of expansion joint filler foam and surrounded by a two foot thick layer of concrete that provides missile protection. The missile shield and expansion joint filler foam configuration mitigates corrosion of the tank by minimizing water and moisture from penetrating inaccessible exterior tank surfaces. Weep holes are located around the circumference of the ECSTs where the concrete missile shield meets the concrete foundation. The weep holes allow drainage of leakage or condensation to the outside perimeter of the ECSTs and will be inspected for water leakage once each refueling cycle.

The roofs and sides of the RWSTs are insulated and jacketed to mitigate corrosion of the tank by minimizing the amount of water and moisture on the exterior surfaces. As an additional preventive measure, sealant is used at the interface between the insulation jacketing and the tank concrete foundation. The RWST insulation jacketing is installed with overlapping seams to provide a protective outer layer and to prevent water intrusion. The sealant at the interface between the insulation jacketing and the RWST tank concrete foundation provides a boundary to mitigate corrosion of the tank bottom surface and the concrete foundation. In addition, the RWST bottom surface is protected by an oil sand cushion and caulk at the interface between the tank external surface and the concrete surface. Periodic inspections normally performed on the caulk at the tank and concrete foundation will be performed on the insulation caulking and concrete foundation interface. An inspection of the caulk at the tank and concrete foundation interface will be included in the sample when the RWST external insulation is removed and sampled for external surface visual examinations.

Detection of Aging Effects (Element 4)

2. NUREG-2191 recommends both visual and volumetric inspection techniques to identify degradation on carbon steel tank external surfaces located outdoors on soil or concrete. The external surfaces of the ECSTs and the ECMTs are encased in a two foot thick reinforced concrete missile barrier with expansion joint filler foam between the external tanks walls and the concrete missile barrier. The concrete missile shields do not allow visual and volumetric examinations of their external surfaces.

Justification for Exception:

The concrete missile shielding and the expansion joint filler foam of the ECSTs and ECMTs act as multiple barriers protecting the external tank surfaces. Weep holes located around the circumference of the ECSTs, where the concrete missile shield meets the concrete foundation, allow for drainage of leakage or condensation to the outside perimeter of the ECSTs. The weep holes will be inspected for water leakage/condensation once each refueling cycle and corrective action taken if excessive leakage is observed. Accessible external metallic tank surfaces visible from inside the ECST and ECMT piping penetration house will be inspected once each refueling cycle as an indication of external ECST and ECMT surface condition.

One-time thickness measurements of a sample of the ECSTs vertical wall will be performed prior to the SPEO to assess potential degradation due to removable access plug leakage. The sample will examine the ECST vertical steel shell region between the three weep holes at the tank bottom associated with removable access plug leakage and vertically from that tank bottom junction to a distance of six feet along the vertical shell at the tank as a region potentially most susceptible to degradation. The inspection results will be projected to end of the SPEO to confirm the ECSTs intended functions will be maintained throughout the SPEO based on the projected rate of degradation. Any degradation not meeting acceptance criteria will require periodic 10-year thickness measurements and a sample expansion along the leakage path consistent with the observed degradation.

The program inspects the external bottom surfaces of the ECSTs and ECMTs that are exposed to a soil or concrete environment by performing volumetric examination thickness measurements.

Enhancements

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

Preventive Actions (Element 2), Parameters Monitored/Inspected (Element 3), Detection of Aging Effects (Element 4), Acceptance Criteria (Element 6), and Corrective Actions (Element 7)

1. Procedures will be revised to require periodic visual inspections of the refueling water storage tanks (RWSTs) be performed at each outage to confirm that the insulation caulking/sealant at the RWST concrete foundation is intact. The visual inspections of caulking/sealant will be supplemented with physical manipulation to detect any degradation. If there are any identified flaws, the caulking/sealant will be repaired or replaced and follow-up examination of the tank's surfaces conducted if deemed appropriate. An inspection of the caulk at the tank and concrete foundation interface will be included in the sample when the RWST external insulation is removed and sampled for external surface visual examinations.

Detection of Aging Effects (Element 4)

2. Procedures will be revised to require visual and surface examination of the exterior surfaces of the RWSTs and CATs be performed to identify any loss of material or cracking. A minimum of either 25, one square foot sections or 20% of the surface area of insulation will be required to be removed to permit inspection of the exterior surface of each tank. The procedure will specify that sample inspection points be distributed in such a way that inspections occur near the bottoms, at points where structural supports, pipe, or instrument nozzles penetrate the insulation, and where water could collect such as on top of stiffening rings. If no unacceptable loss of material or cracking is observed, subsequent external surface examinations of insulated tanks will inspect for indications of damage to the jacketing, evidence of water

intrusion through the insulation, or evidence of damage to the moisture barrier of tightly adhering insulation.

3. Procedures will be revised to require ECST weep holes be inspected for water leakage/condensation once each refueling cycle and corrective action taken if excessive leakage is observed. Accessible external metallic tank surfaces visible from inside the ECST piping penetration house will also require inspection once each refueling cycle as an indication of external ECST surface condition. Volumetric examination thickness measurements of the bottom of both ECMTs (100% of the surface exposed to soil) and both emergency condensate storage tanks will be performed and will occur during each 10-year period starting ten years before the subsequent period of extended operation. Results will be forwarded to engineering for evaluation and the need for additional inspections will be determined based on projected corrosion rates.

   One-time thickness measurements of a sample of the ECSTs vertical wall will be performed prior to the SPEO to assess potential degradation due to removable access plug leakage. The sample will examine the ECST vertical steel shell region between the three weep holes at the tank bottom associated with removable access plug leakage and vertically from that tank bottom junction to a distance of six feet along the vertical shell at the tank as a region potentially most susceptible to degradation. The inspection results will be projected to end of the SPEO to confirm the ECSTs intended functions will be maintained throughout the SPEO based on the projected rate of degradation. Any degradation not meeting acceptance criteria will require periodic 10-year thickness measurements and a sample expansion along the leakage path consistent with the observed degradation.

4. Procedures will be revised to require volumetric examination thickness measurements of the bottom of both FWSTs and both RWSTs be performed each 10-year period during the subsequent period of extended operation starting ten years before the subsequent period of extended operation. Results will be forwarded to Engineering for evaluation and the need for additional inspections will be determined based on projected corrosion rates.

5. For the carbon steel tanks (FWST, ECST, ECMT), procedures will be revised to provide non-ASME Code inspection guidance related to lighting, distance, offset, and surface conditions. The revised procedure will require the inspector confirm adequate lighting is available at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two feet or less is recommended. For distant surface inspections, viewing aids such as binoculars may be used. For internal inspections, accessible surfaces will be inspected. Cleaning will be performed as necessary to allow for a meaningful examination. If protective coatings are present, the condition of the coating will be noted.

Corrective Action (Element 7)

6. A new procedure will be developed to specify that additional inspections be performed consistent with NUREG-2191.

   If any inspections do not meet the acceptance criteria, additional inspections are conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending).

   a. For inspections where only one tank of a material, environment, and aging effect was inspected, all tanks in that grouping are inspected.

   b. For other sampling based inspections there will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at the other unit.

      The additional inspections will be completed within the interval (i.e., 10-year inspection interval) in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the 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 any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the Corrective Action Program. However, for one-time inspections that do not meet acceptance criteria, inspections are subsequently conducted at least at 10-year inspection intervals.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Outdoor and Large Atmospheric Metallic Storage Tanks* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that 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. The inspections included ultrasonic thickness (UT) measurements of the tank floor as part of

the initial inspection for the first license renewal period. There was little evidence of corrosion, but there was minor blistering of the coating on the tank floor. Based on the observed erosion rate, the remaining service life of the tank bottom is more than twenty years. Internal Inspection of the Unit 1 ECST to assess the extent of corrosion or coating damage is scheduled to be performed in 2022.

2. In December 2008, the interior surface of the Unit 2 ECST was inspected in the filled condition. The inspections included ultrasonic testing (UT) measurements of the tank floor as part of the initial inspection for the first license renewal period. There was little evidence of corrosion, but there was minor blistering of the coating on the tank floors. Based on the observed erosion rate, the remaining service life of the tank bottom is more than twenty years.

3. During the Spring 2014, Unit 2 Refueling Outage, the interior surface of the Unit 2 RWST was inspected in the filled condition. The inspections included UT measurements of the tank floor. The inspections showed only minor corrosion in the stainless steel bottom plate. Based on only minor corrosion being found, the tank is scheduled for a twenty year inspection interval. Inspection results and calculations of the long term corrosion rate based on industry standard API-653 determined the remaining life of the RWST is 335 years. There were no corrective actions required.

4. In August 2014, the interior surface of the Unit 1 ECMT was inspected in the filled condition. The inspection was performed using divers and video equipment. The inspection observed only minor rusting, 1% or less, in localized areas. Interior piping and penetrations were observed to be in good condition. The internal coating was in good condition with the coating being 99.9% intact.

5. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

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

6. In May 2017, an internal inspection of the Unit 2 ECST was performed. Small blistering and pinhole damage was identified in areas of the coating along the tank walls. Internal coating repairs have been scheduled in work management.

7. In November 2017, as part of oversight review activities, the Tank Inspection Activities (UFSAR Section 18.1.3) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

8. In January 2018, an aging management activity effectiveness review was performed of the Tank Inspection Activities (UFSAR Section 18.1.3). Information from the summary of that effectiveness review is provided below:

   The Tank Inspection Activities is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. Key activities of the Tank Inspection Activities that were reviewed include completed carbon steel tank inspections, including some performed prior to the development of the Tank Inspection Activities. A review was also performed of the Corrective Action Program from 2006 through 2017 for age-related degradation of tanks within the scope of license renewal.

   The ECSTs were repaired and re-coated in 1988 to preclude further corrosion. Unit 1 internal inspection results in 1992 and 1997 indicated that the emergency condensate storage tank was in excellent condition. Unit 2 inspection results during 1993, 1996, and 2000 found excellent interior tank conditions. Additional inspections of the ECSTs for both units in December 2008 again confirmed the excellent condition of the tanks. The Unit 2 tank was inspected in May 2017. The inspection found minor blistering and pinholes in the internal coating. Internal coating repairs have been scheduled in work management. There were no new aging management concerns identified.

   The fire protection/domestic water storage tanks '1A' and '1B' were inspected in December 2008. Visual inspections of the inside surface confirmed that the tanks have some corrosion. The bottom coatings were blistered but intact. The tanks were inspected in 2014 and the most significant degradation was noted on the tank floor. The results of the visual inspection were that coating degradation was continuing, and that some bare metal was evident. Volumetric examinations found some thinning of the tank floor. An engineering evaluation projected that the tank floor plate would reach minimum acceptable thickness prior to the expiration of the operating licenses. The inside walls of the tanks had some coating failure. The measured values for wall thicknesses provided a projected useable lifetime of between 7.9 and 13.6 years (from December 2008) for the '1A' tank and between 13.8 and 19.1 years for the '1B' tank before the bottom plate would reach the minimum acceptable wall thickness. An engineering evaluation was required to identify additional actions to address the limited lifetime of the tanks. Additional actions include future inspections to identify the corrosion rate of thin wall areas and to either repair the tank bottoms in the near future or replace the tanks.

   The following carbon steel tank inspections did not identify age-related degradation:

- April 2004, EDG coolant expansion tank (internal visual inspection)
- September 2005, underground fuel oil storage tanks (internal visual inspection, wall thickness measurement)
- February 2007, above-ground fuel oil storage tanks (external visual inspection, wall thickness measurement)
- June 2009, AAC diesel generator air receiver (wall thickness measurement)
- February 2007, AAC diesel generator fuel oil tank (external visual inspection, wall thickness measurement)
- April 2007, security diesel generator fuel oil storage tank (helium leak test)
- February 2007, diesel-driven fire pump fuel oil tank (exterior visual inspection, wall thickness measurement)
- February 2007, emergency service water pump diesel fuel oil storage tank (exterior visual inspection, wall thickness measurement)

The successful inspection of the Unit 2 RWST and Unit 1 CAT at North Anna Power Station in 2010 found no indications of age-related degradation. That result is also applicable to SPS since the RWSTs and CATs at SPS and North Anna Power Station are both made of stainless steel and the tanks have similar installation and operating environments. Surry Power Station allows the inspections of stainless steel tanks to be extrapolated to other tanks that are fabricated from a similar material, installation, and operating environment combination.

In November 2013, based on IE Notice 2013-18 (IEN 13-18), "Refueling Water Storage Tank Degradation," that was issued to inform licensees of potential issues associated with leakage due to flaws in RWSTs, SPS issued an OE document addressing RWST degradation. No previous RWST leakage was identified. In 2014, an inspection of the Unit 2 RWST identified only minor corrosion issues.

Based on industry operating experience, fleet programs were developed for inspection of underground piping and tank integrity and condition assessment of internally coated/lined tanks, components, and pipes subject to immersion service. The Tank Inspection Activities (UFSAR Section 18.1.3) incorporated applicable buried components and coated components aging management techniques from the fleet programs.

The above examples of operating experience provides objective evidence that the *Outdoor and Large Atmospheric Metallic Storage Tanks* program includes activities to perform visual inspections of tank internal bare metal surfaces, surface examination of external tank surfaces, and thickness measurements of tank bottoms to identify cracking or loss of material for aboveground metallic tanks within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Outdoor and Large Atmospheric Metallic Storage Tanks* program are evaluated to ensure there is no significant impact to the safe operation of the plant and

corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Outdoor and Large Atmospheric Metallic Storage Tanks* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Outdoor and Large Atmospheric Metallic Storage Tanks* program, following enhancement, 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. 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.~~ (Exception 1 Deleted - Set 2 RAIs)

2.

(Exception 2 Deleted - Set 1 RAIs)

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 baseline inspections (100% of accessible coatings/linings) of the following tanks, piping, and miscellaneous components within the scope of subsequent license renewal and inspection intervals will not exceed those specified in NUREG-2191, Table XI.M42-1, "Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers." (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

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._

The Open Cycle Cooling Water (OCCW) program (B2.1.11) will manage aging effects of CFRP linings in OCCW systems using ASME Code Case N-871.

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.

The Open Cycle Cooling Water (OCCW) program (B2.1.11) will manage aging effects of CFRP linings in OCCW systems using ASME Code Case N-871.

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.

<u>The Open Cycle Cooling Water (OCCW) program (B2.1.11) will manage aging effects of CFRP linings in OCCW systems using ASME Code Case N-871.</u>

The above examples of operating experience provide objective evidence that the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program includes activities to perform visual inspections of internal surfaces to identify deficient or degraded coatings/linings for piping, piping components, heat exchangers and tanks within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects

are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program, following enhancement, will effectively manage aging prior to loss of intended function.

Conclusion

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

B2.1.34 Structures Monitoring

Program Description

The *Structures Monitoring* program is an existing condition monitoring program that manages aging of the structures and components that are within the scope of subsequent license renewal by managing the following aging effects:

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

The *Structures Monitoring* program implements the requirements of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," consistent with guidance of U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," and Nuclear Management and Resources Council 93-01, "Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants". The scope of the *Structures Monitoring* program includes structures and components in the scope of subsequent license renewal. The program relies on periodic visual inspections to monitor and maintain the condition of structures and components within the scope of subsequent license renewal. Inspections are conducted by qualified personnel at a frequency not to exceed five years, except for wooden poles, which will be inspected on a 10-year frequency. The interval between successive recurring inspections may be decreased based on conditions discovered in previous inspections.

Structural monitoring inspections consist primarily of periodic visual examination of accessible structures and components performed by qualified personnel. For concrete and associated components, ACI-349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures," and other applicable industry documents are used as guidance for the inspections, inspector qualifications, and evaluation of inspection results. The inspection program for structural steel is similar to the concrete program and is based on the guidance provided in the AISC Specification for Structural Steel Buildings and Code of Standard Practice. For earthen structures, evaluation of inspection results is performed by a qualified civil/structural engineer.

Procedures will include preventive actions to provide reasonable assurance of structural bolting integrity, as discussed in Electric Power Research Institute (EPRI) documents (such as EPRI NP-5067, "Good Bolting Practices, A Reference Manual for Nuclear Power Plant Maintenance Personnel," and TR-104213, "Bolted Joint Maintenance & Application Guide"), American Society for Testing and Materials (ASTM) standards, and AISC specifications, as applicable.

In order to evaluate the potential of water to cause degradation of inaccessible below-grade concrete, samples of groundwater will be taken at intervals not to exceed five years. The water chemistry is evaluated, and should the results of water testing indicate potentially harmful levels of substances such as chlorides > 500 ppm, sulfates > 1,500 ppm, or a pH < 5.5, inaccessible areas are assessed for aging when aging degradation exists in accessible areas and opportunistically inspected when excavated.

Ground water monitoring has shown the ground water to be non-aggressive, except for one sampling point. In 2007, a sample with a significantly high chloride level was obtained from the Turbine Building sump. Subsequent sample results from this sump have found additional chloride levels above the acceptance limit. An inspection was performed to assess the structure for any degradation that could be attributed to the elevated levels of chloride. The inspection found no evidence of significant degradation. There have been no indications of concrete degradation due to elevated chloride levels anywhere in the plant. Engineering continues quarterly monitoring of the ground water in this sump.

For surfaces provided with protective coatings, observation of the condition of the coating is an effective method for identifying the absence of degradation of the underlying material. Therefore, coatings on structures within the scope of the *Structures Monitoring* program are inspected only as an indication of the condition of the underlying material.

ASME Code, Section XI visual examinations (VT-1) or surface examinations will be conducted to detect cracking of stainless steel and aluminum components exposed to aqueous solutions or air environments containing halides. A minimum sample of 25 inspections will be performed from each of the aluminum and stainless steel component populations every ten years.

If any sampling-based inspections to detect cracking in aluminum and stainless steel do not meet the acceptance criteria, additional inspections will be conducted, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (i.e., 10 year inspection interval) in which the original inspection was conducted. Where practical, the inspections will focus on the bounding or lead components most susceptible to aging because of time in-service, severity of operating conditions, and lowest design margin.

Concrete inspection results are evaluated to identify changes that could be indicative of Alkali-Silica Reaction (ASR) development. If indications of ASR development are identified, the evaluation considers the potential for ASR development in concrete that is within the scope of the *ASME Section XI, Subsection IWL* program (B2.1.30), the *Structures Monitoring* program (B2.1.34), or the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (B2.1.35). In 1988, a research study was performed to evaluate the degradation processes that could affect the reinforced concrete structures. Concrete core samples were secured from the intake canal, Unit 1 Condensate Storage Tank Missile Shield, Unit 2 Safeguards Building and Unit 2 Containment. Based on testing of these samples, the study concluded that there was no evidence of ASR.

Evaluation of inspection results includes consideration of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.

Structural sealants, seismic gap joint filler, vibration isolation elements, and other elastomeric materials are monitored for cracking, loss of material, and hardening. These elastomeric elements are acceptable if the observed loss of material, cracking, and hardening will not result in a loss of intended function. Visual inspection of elastomeric elements is supplemented by tactile inspection to detect hardening if the intended function is suspect.

Procedures will include preventive actions to ensure bolting integrity for replacement and maintenance activities by specifying proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting. For structural bolting consisting of ASTM A325, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural

Connections publication, "Specification for Structural Joints Using High-Strength Bolts," will be used.

Spent fuel pool (SFP) liner leakage through the leak chase channels is monitored. An alarm is provided on the SFP to sound at a level loss of approximately 0.5 feet (UFSAR Section 9.5.3.3). A review of recent leak chase channel monitoring reports shows acceptable leakage rates with no tell-tale drains being completely blocked.

The *Masonry Walls* program (B2.1.33) and the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (B2.1.35) are implemented as part of this program.

NUREG-2191 Consistency

The *Structures Monitoring* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.S6, Structures Monitoring.

Exception Summary

None

Enhancements

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

Scope of Program (Element 1)

1. Procedures will be revised to include inspection of the following structures that are within the scope of subsequent license renewal: decontamination building, radwaste facility, health physics yard office building, laundry facility, and machine shop. Inspections for the added structures will be performed under the enhanced program in order to establish quantitative baseline inspection data prior to the subsequent period of extended operation. (Revised Change Notice 1)
2. Procedures will be revised to add the oiled-sand cushion to the inspection of the fire protection/domestic water tank foundation. (Added Change Notice 3)

Preventive Actions (Element 2)

3. Procedures will be revised to include preventive actions to ensure bolting integrity for replacement and maintenance activities by specifying proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting. For structural bolting consisting of ASTM A325, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, "Specification for Structural Joints Using High-Strength Bolts," will be used.

4. The checklist for structural and support steel will be revised to indicate: "Are any connection members loose, missing or damaged (bolts, rivets, nuts, etc.)?". (Added Change Notice 2)

Detection of Aging Effects (Element 4)

5. Procedures will be revised to eliminate options for inspector qualifications that are not consistent with ACI 349.3R-002. (Revised Change Notice 2)
6. Procedures will be revised to specify that wooden pole inspections will be performed every ten years by an outside firm that provides wooden pole inspection services that are consistent with standard industry practice. Visual examinations may be augmented with soundings or other techniques appropriate for the type, condition, and treatment of the wooden poles, including borings to determine the location and extent of decay and excavation to determine the extent of decay at the groundline. (Revised Change Notice 2)
7. Procedures will be revised to specify that evaluation of inspection results includes consideration of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. (Added Change Notice 2)
8. Procedures will be enhanced to specify VT-1 inspections to identify cracking on stainless steel and aluminum components. A minimum of 25 inspections will be performed every ten years during the subsequent period of extended operation from each of the stainless steel and aluminum component populations assigned to the Structures Monitoring program. If the component is measured in linear feet, at least one foot will be inspected to qualify as an inspection. For other components, at least 20% of the surface area will be inspected to qualify as an inspection. The selection of components for inspection will consider the severity of the environment. For example, components potentially exposed to halides and moisture would be inspected, since those environmental factors can facilitate stress corrosion cracking. (Added Change Notice 2)
9. Procedures will be enhanced to specify that for the neutron shield tank (NST), loss of material due to corrosion, other than superficial corrosion, will be evaluated to ensure that the NST will continue to perform its intended functions, including structural support of the RPV. (Added - Set 2 RAIs)

Corrective Actions (Element 7)

10. Procedures will be enhanced to specify for the sampling-based inspections to detect cracking in stainless steel and aluminum components, additional inspections will be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement for all components constructed of the same material and exposed to the same environment. No fewer than five additional inspections for each inspection that did

not meet acceptance criteria or 20 percent of each applicable material, environment, and aging effect combination will be inspected, whichever is less. Additional inspections will be completed within the 10-year inspection interval in which the original inspection was conducted. The responsible engineer will initiate condition reports to generate work orders to perform the additional inspections. The responsible engineer will evaluate the inspection results, and if the subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted. The responsible engineer will then determine the further extent of inspections. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies will be adjusted as determined by the Corrective Action Program. (Added Change Notice 2)

11. Procedures will be enhanced to specify that evaluation of neutron shield tank findings consider its structural support function for the reactor pressure vessel. (Added Change Notice 3)
12. Procedures will be enhanced to also include LOCAs as events that require evaluation for potentially degraded structures by Civil/Mechanical Design Engineering. (Added Change Notice 3)

Operating Experience Summary

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

1. In March 2007, a condition report (CR) was written to document a ground water monitoring sample with a chloride level of 1210 ppm, which exceeded the acceptance limit of <500 ppm. This sample was obtained from the Turbine Building sump. Corporate and site Engineering continue to monitor the quarterly sample results from the Turbine Building sump and have found additional chloride levels above the acceptance limit, as high as 2700 ppm. An inspection of the Turbine Building sump was performed in July 2008 to assess the sump structure for any degradation that could be attributed to the elevated level of chlorides. The inspection found no evidence of significant degradation to the interior concrete. There are no safety-related components in the vicinity of the Turbine Building sump, and there have been no indications of concrete degradation due to elevated chloride levels anywhere in the plant.

   The source of the chlorides has not been determined. The Turbine Building sump is the deepest dewatering point and closest to the Intake Canal where expected underground

leakage from the canal could influence the chloride level. The potential for in-plant sources of chlorides reaching the sump via secondary drains or local ground water was studied and determined to be unlikely. An Engineering evaluation concluded that, while the chloride level has remained high in the Turbine Building sump, the other sumps/piezometer well locations, some of which are located in close proximity to the Turbine Building sump, have been found to be consistently within acceptable levels. Engineering will continue to monitor the chloride levels in the Turbine Building sump on a quarterly basis. The plant procedure has been revised to maintain sampling requirements so that trending may continue but eliminate the comparison to the acceptance criterion for this sampling point.

2. In May 2011, a spall was found on the inside concrete surface of the bioshield wall of the Unit 2 Containment 'C' steam generator cubicle. The spall was approximately six inches long by six inches wide and 1-1/4 inches deep. The reinforcing steel was not exposed. It was determined that the bioshield wall remained fully functional, but the spalled concrete required repair prior to unit startup to prevent potential degradation of the reinforcing steel. A work order was submitted and the spalled concrete has been repaired.

3. In December 2011, several embedded anchor bolts for the condenser unit of a Unit 1 Control Room chiller were found to be degraded. The anchor bolts displayed signs of corrosion and material loss. A work order was submitted and the anchor bolts were repaired in December 2011, which consisted of chipping the existing concrete around the anchor bolts until sound metal was reached, performing a weld repair of each anchor bolt, and repairing the concrete slab.

4. In October 2012, leakage (approximately one gpm) was identified in the bottom portion of the steel to concrete joint (interface between the steel elbow and the concrete pipe) of the Unit 2 'D' 96-inch circulating water line. Corrosion and coating failure on the bottom third of the pipe was observed at this location. The urethane seal around the leading (upstream) edge of the joint was also missing and degraded. A work order was submitted and the Unit 2 'D' 96-inch circulating water line joint has been repaired.

5. In January 2013, the Service Building roof was leaking, causing water to collect in two locations on the floor of the Service Building hallway. The first location was near the #1 EDG room. The second location was approximately halfway between the doors to the health physics area and the door to the operations annex. A work order was submitted and degraded roof areas were repaired.

6. In December 2014, a CR was written to document a ground water monitoring sample that showed a chloride level of 610 ppm. The sampling point that exhibited unacceptable chloride levels is located adjacent to the Intake Canal, which draws water from the river. Three months later the same sampling point was found to have chlorides at 676 ppm. These values exceeded the acceptance limit of <500 ppm. The CR evaluation determined that the elevated chloride level was probably due to unusually low rain fall on the James River, temporarily increasing its natural salinity. Results from subsequent monitoring of ground water have been acceptable, and no degradation of concrete due to elevated chloride levels has been identified.
7. In December 2015, an effectiveness review of the Civil Engineering Structural Inspection Activity (UFSAR Section 18.2.6) was performed. The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. No gaps were identified by the effectiveness review.
8. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.
9. In November 2017, as part of oversight review activities, the Civil Engineering Structural Inspection Activity (UFSAR Section 18.2.6) AMA owners confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments required in UFSAR Chapter 18. Security lighting poles were within the scope of license renewal but were not inspected during the Civil Engineering Structural Inspection Activity cycle completed in 2012. The omission of the security lighting poles from the 2012 inspection cycle was entered in the Corrective Action Program. In December 2017, Civil Engineering inspected the light poles and noted no degradation. The License Renewal Application and supporting documentation were reviewed for in-scope structures requiring inspection, and that information was cross-referenced with the implementing procedure to confirm aging management program commitments required by UFSAR Chapter 18 were satisfied. The security lighting poles are identified in the implementing procedure as being within scope of license renewal and will be inspected during subsequent structural inspections.

10. In January 2018, an aging management program effectiveness review was conducted for the Civil Engineering Structural Inspection Activity (UFSAR Section 18.2.6), which include the *Structures Monitoring* program (B2.1.34), *Masonry Walls* program (B2.1.33) and the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (B2.1.35). Information from the summary of that effectiveness review is provided below:

    The Civil Engineering Structural Inspection Activity is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. Key activities of the AMA that were reviewed included structural inspections for aging management that have been incorporated into the periodic inspections performed for Maintenance Rule compliance. Maintenance Rule inspections, along with trending and evaluation for evidence of aging effects, ensure the continuing capability of civil engineering structures to meet their intended functions consistent with the current licensing basis. A 10-year review of inspection results and corrective actions did not identify any aging that resulted in a loss of intended function(s).

11. In March 2018, the existing Structures Monitoring program was revised to improve the inspection techniques and to adopt new inspection techniques to manage aging effects associated with ASR degradation of concrete structures and components consistent with industry operating experience IE Notice 2011-20 (IN 2011-20), "Concrete Degradation by Alkali-Silica Reaction," and EPRI Report #3002005389 (2015), "Tools for Early Detection of ASR in Concrete Structures."

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

Conclusion

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

Enclosure 6

SUPPORTING DOCUMENTS FOR RAI RESPONSES

Attachment 1: "In-house audit response-NRC Audit for SPS's SLR Information for TRP 12 CASS 3 4 19 Tomes" (RAI B2.1.6-2)

Attachment 2: SGMP-IL-16-02, Attachment 1 (RAI B2.1.10-1)

Attachment 3: EPRI 300200285 Cycle Assumptions / SPS Cycle Limit Design and Transient Comparison Table (RAI B2.1.10-1)

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

Enclosure 6

Attachment 1

"IN-HOUSE AUDIT RESPONSE-NRC AUDIT FOR SPS'S SLR INFORMATION FOR TRP 12 CASS 3 4 19 TOMES" (RAI B2.1.6-2)

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

"In-house audit response-NRC Audit for SPS's SLR Information for TRP 12 CASS 3 4 19 Tomes"

Provided below is text from "In-house audit response-NRC Audit for SPS's SLR Information for TRP 12 CASS 3 4 19 Tomes that was requested in RAI B2.1.6-2."

Item 1

Discuss why the stress for straight pipe is adequate for the stress of the elbows in the CASS assessment.

Discussion for Item 1

The stress intensity factors for surface flaws in cylinders (straight pipe) can be used for elbows as long as the stresses include the geometric factors associated with the curvature of the elbow. The industry accepted document, API-579-1, Fitness-For-Service, Annex C.7 also states the following:

> **C.7 Stress Intensity Factor Solutions for Elbows and Pipe Bends**
>
> The stress intensity factor solutions for cylinders can be used for elbows and pipe bends if the stress at the location of the crack is determined considering the bend geometry and applied loads.

Therefore, the fracture mechanics analysis performed for CASS evaluation already includes the stress indices in the development of the stresses, which are then used to calculate the stress intensity factors in a cylinder pipe geometry.

It should be noted that for the reactor coolant loop (RCL) CASS flaw tolerance analysis, there are also other conservatisms in the analysis which make this evaluation bounding,

1. Bounding loads from both Units 1 and 2
2. Bounding loads within each hot, crossover, and cold leg elbows.
3. Absolute summation of the deadweight, thermal expansions, seismic, and LOCA loads.
4. Use of conservative Z-factor for SAW welds to determine the maximum allowable end of evaluation flaw sizes for elbows (which is a base metal).
5. Delta ferrite based on all susceptible elbow population are considered from both Units 1 and 2.
6. Use of LOCA loads based on residual heat removal, surge and accumulator pipe break (note that all of these breaks are planned to be eliminated with the use of extended LBB evaluation for these lines in the near future).
7. It is has been established through testing and operating history that the most likely location for the initiation of a flaw is in the weld region not the base metal.
8. Base metal elbows are rigorously inspected during pre-service with multiple levels of liquid penetrant examinations (PT) and radiographic examinations (RT)

(see Section 4.1.1 of EPRI MRP-362, Revision 1, "Technical basis for ASME Section XI Code Case N-838 – Flaw Tolerance Evaluation of Cast Austenitic Stainless Steel (CASS) Piping Components"). Typical defects are surface porosity, linear discontinuities, inclusions and shrinkage effects. In all cases, these defects are excavated to sound metal and repaired by welding, or the part is discarded.

Lastly, it should be noted that the ASME Section XI inspection requirement for CASS components (pipe/elbows) is provided in Paragraph IWB-2500. The examination area is restricted to pressure retaining welds in piping, which is examination category B-J (see Table IWB-2500-1). The examination area for inspection is provided in Figure IWB-2500-8 for similar welds in piping. Based on the area of examination from Figure IWB-2500-8, only the weld and ½" into the base metal (straight pipe) on either side of the weld is required to be inspected. As a result, the flaw tolerance analysis is restricted to the region of the weld and the adjacent base metal. The K solutions in the region of interest are therefore based on a straight pipe.

The same guidance for flaw postulation and evaluation of CASS piping (elbows as well) is also provided in ASME Section XI Code Case N-838, "Flaw Tolerance Evaluation of Cast Austenitic Stainless Steel Piping." As discussed in Section 1(b) of Code Case N-838, the scope is for flaw tolerance evaluations for postulated flaws in CASS base metal adjacent to welds in conjunction with license renewal application. More specifically, Section 3(b)(1) of Code Case N-838, states to "Select locations for postulating flaws in susceptible CASS piping adjacent to welds in accordance with the defined volume in Figure IWB-2500-8." Therefore, with the use of this code case for flaw tolerance evaluations, the flaws are always postulated in straight pipes and not the elbow intrados/extrados.

Code Case N-838 has been reviewed by the NRC without any condition on flaw postulation guidelines (see NRC 10 CFR part 50, NRC-2017-0024, Approval of American Society of Mechanic Engineers' Code Cases, Proposed Rule, Federal Registrar Vol. 83, No.159, August 16, 2018). Thus, the flaw postulation in straight pipe in the vicinity of the examination zone of the weld as per ASME Section IWB-2500-8 is acceptable. The technical basis for Code Case N-838 is MRP-362, Revision 1, and the flaw evaluation guidance in MRP-362 is also based on fracture mechanics of straight pipes, not of elbows.

Nevertheless, as mentioned above, for the RCL CASS flaw tolerance evaluation, stress indices to account for the curvature of the elbows are incorporated when calculating stresses. These stresses are then applied to calculate stress intensity factors in a straight pipe for use in the fracture mechanics analysis. Thus, the RCL CASS flaw evaluation and postulation is consistent and conservative with respect to industry practice.

NRC has previously accepted the Kewaunee RCL CASS flaw tolerance evaluation (for license renewal), which also was performed based on the same methodology as described above (stresses include elbow indices, and stress intensity factor based on straight pipe) (see Docket No. 50-305, pg. 4-48, ML103090024, ML103000131).

Item 2

Discuss assessment of the cold leg circumferential flaw information in Table 6-1 and Figure 6-6 of WCAP-18258.

Discussion for Item 2

Figures 6-1 through 6-6 of WCAP-18258 are flaw tolerance charts for the susceptible piping components in the hot leg, crossover leg, and cold leg for both axial and circumferential flaws. The purpose of these flaw tolerance charts is to identify the maximum acceptable initial flaw size for a given plant operation duration (80 years). For a typical flaw tolerance chart, the flaw shape parameter (a/l) is plotted as the abscissa from a/l = 0.1 (l/a = 10) to a/l = 0.5 (l/a = 2) and the flaw depth parameter (a/t) expressed as a ratio of the through-wall thickness is plotted as the ordinate from 0.0 to 0.8. Therefore, these flaw charts encompass various different postulated flaw cases analyzed based on different aspect ratios (with l/a ranging from 2 to 10). Any flaw which falls below the allowable flaw size curve in Figures 6-1 through 6-6 is acceptable in accordance with the IWB-3640 acceptance criteria for 80 years.

Using Figure 6-6 (see Figure 2 below) as an example for explanation purposes; the chart is for postulated circumferential flaws in the cold leg. Table 6-1 (see Figure 1 below) shows supplemental information for explanation since it contains numerical values. The information in Table 6-1 is for an aspect ratio of l/a = 6 (or a/l = 0.1666), an aspect ratio of 6 is picked because it is a common flaw case used throughout the industry for fracture mechanics assessment and evaluation.

Figure 6-6, includes a single blue curve labeled as 80 years. This curve was constructed by first determining the maximum allowable end of evaluation flaw size. The maximum end-of-evaluation flaw size is not shown on the curve in Figure 6-6. However, in Table 6-1, the maximum end-of-evaluation flaw size for AR (aspect ratio) = 6 is 50% (a/t) of the wall thickness. The maximum allowable end of evaluation flaw size of 50% is based on limit load analysis per ASME Section XI App C. This flaw size is calculated based on plastic collapse and is also frequently called the critical flaw size. The circumferential maximum allowable end of evaluation flaw sizes is based upon dead weight, pressure, thermal expansion, seismic, and LOCA loads (see Table 2-2 of WCAP-18258). The maximum allowable end of evaluation flaw size is the largest final flaw size for which the pipe can theoretically fail based on ASME Section XI guidance.

An acceptable initial flaw size is then back-calculated based on fatigue crack growth by accounting for all the design transients and cycles for 80 years. Therefore, for the example case (circumferential flaw at the cold leg, AR = 6), it would take a very large

postulated flaw size of 49% of the wall thickness to grow to the maximum allowable end-of-evaluation of 50% of the wall thickness (see Figure 3). Thus the crack growth for this particular case is very small, basically 1% growth in 80 years.

The blue curve of Figure 6-6, plotted for a/l = 0.166 (AR = 6:1), shows the acceptable initial flaw size = 49%. This value of 49% of the wall thickness is also presented in Table 6-1 as the acceptable initial flaw size. Therefore, this case demonstrates that the cold leg piping can tolerate a flaw size of 49% of the wall thickness for 80 years for AR = 6. Any flaws with AR = 6 that are less than 49% of the wall thickness are acceptable for 80 years. Similar to AR = 6, the blue curve is composed of other aspect ratios ranging from 2 to 10, and the calculated acceptable initial flaw sizes are graphically illustrated on Figure 6-6. Any flaw sizes that fall below the blue curve on Figure 6-6 are acceptable for 80 years based on ASME Section XI, and any flaws above the blue curve are unacceptable. As a concluding remark in Table 6-1, the difference between the acceptable initial flaw size and the maximum allowable end of evaluation flaw sizes is the amount of crack growth in 80 years. For the case of AR = 6 for the cold leg circumferential flaw, the growth is only 1%.

Table 6-1: Acceptable Initial Flaw Sizes (% Through-wall Thickness) for Susceptible CASS Elbow Components
(Aspect Ratio = 6, For a Service Life of 80 years)

Location	Axial Flaw		Circumferential Flaw	
	Acceptable Initial Flaw Size	Maximum Allowable End-of-Evaluation Period Flaw Size	Acceptable Initial Flaw Size	Maximum Allowable End-of-Evaluation Period Flaw Size
Hot Leg	46%	60%	59%	71%
Crossover Leg	52%	58%	68%	75%
Cold Leg	54%	60%	49%	50%

Figure 1: Table 6-1 from WCAP-18258

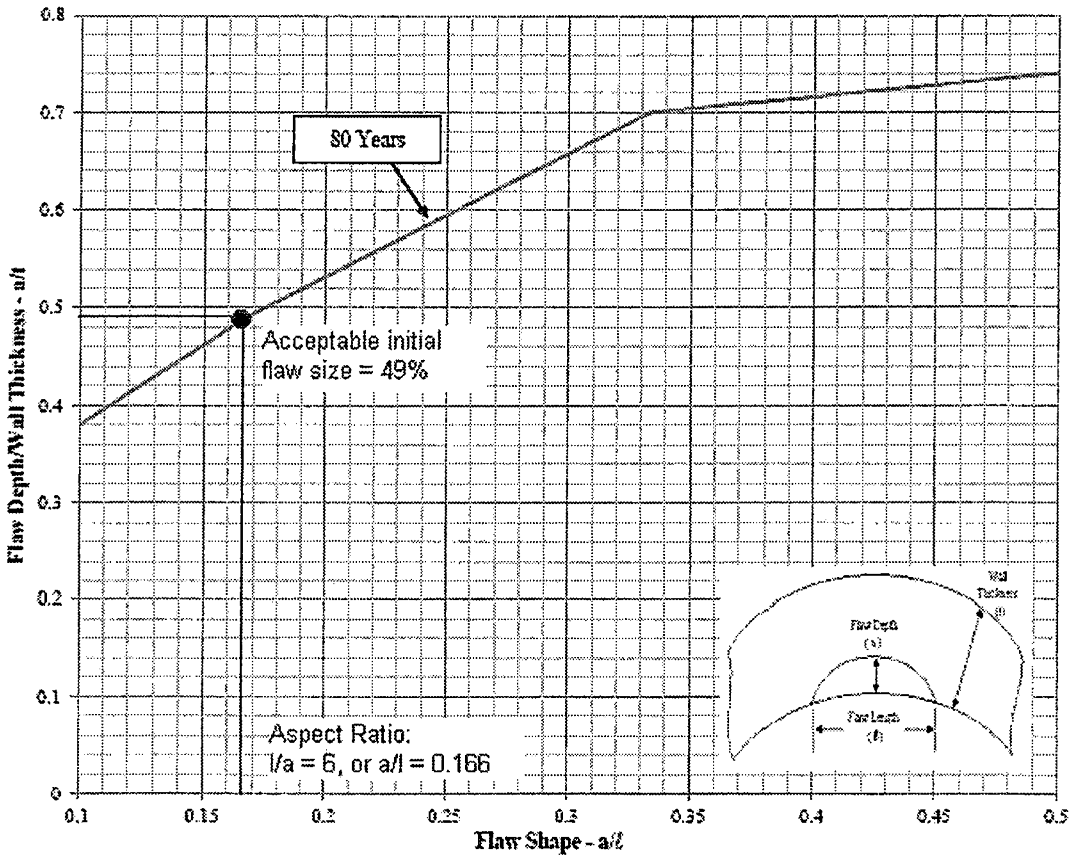

Figure 6-6 Circumferential Flaw Tolerance Chart for Susceptible CASS Elbow Components in the Cold Leg

Figure 2: Figure 6-6 from WCAP-18258

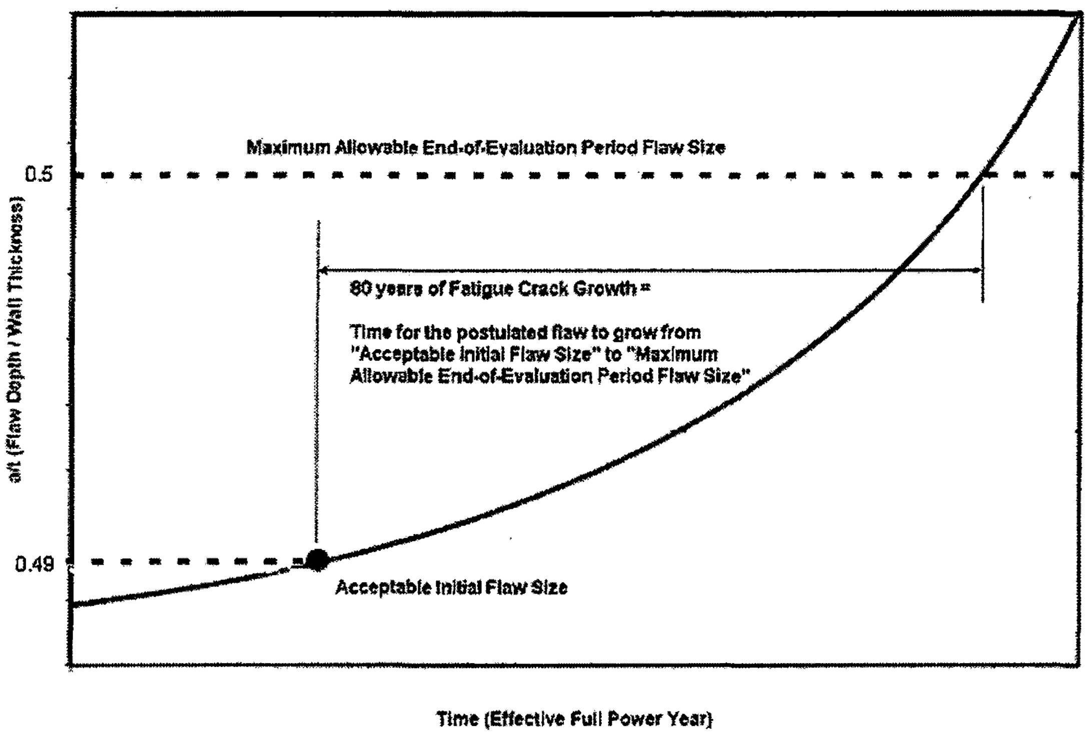

Figure 3: Graphically portrayal of fatigue crack growth from acceptable initial flaw size to maximum allowable end of evaluation flaw size

Enclosure 6

Attachment 2

<u>SGMP-IL-16-02, ATTACHMENT 1 (RAI B2.1.10-1)</u>

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

Attachment 1

Guidance for Addressing Aging Management Plans for Steam Generator Channel Head Components

If Alloy 600 or Alloy 600 Variations were used, reviewer should continue with this list to verify that an adequate basis for concluding that the situation is bound by the analyses performed in the industry technical basis (EPRI Technical Reports 3002002850, 1014982, 1020988). If all responses are Yes or other justification is provided, the plant is bound.

Evaluation of Divider Plate Assemblies		
1.	Divider plate thickness is greater than or equal to 1.9 inches. 2.00 inches per VTM-000-38-W893-00035, pdf page 26	SAT
2.	Channel head wall thickness at the triple point location is greater than or equal to 5.20 inches. 5.2 inches minimum per 11448(11548)-WMKS-RC-E-1A(1B)(1C)	SAT
3.	Tube sheet is greater than or equal to 21 inches thick 21.03 inches per VTM-000-38-W893-00035, pdf page 26	SAT
4.	The steam generator that was modeled included a stub runner. The stub runner is a feature important to divider plate alignment during manufacturing. The stub runner facilitates being able to adjust the divider plate position and still make the weld without creating excessive distortion of the divider plate. A stub runner plate 3 inches tall is typical and was used in the analysis. Other designs may or may not use a stub runner. Provide justification that the plant's steam generator design would be bounded by the analysis. Stub runner is included, per CO-ETE-000-ETE-CEP-2012-1003.	SAT
5.	The bottom head is a carbon steel casting SA-216 WCC or material of similar chemical composition and mechanical properties. Material specification SA-508 Grade 3, Class1 (formerly SA-508 Class 3) forging is one material that has been evaluated as similar and the analysis is bound by the properties of the casting. SA-216, WCC per VTM-000-38-W893-00035 and UFSAR Table 4.2-1	SAT
6.	The upper vessel wall is SA-533 Type A Class 1 carbon steel or a material having similar properties. All Types and Classes specified in SA-533 are considered similar as the analysis is bound by the properties of the SA - 533 Type A Class 1 material. SA-533 Grade A, Class 1 per SU-VTM-000-38-W893-00035 and EDWG-000-1875E12 Sh. 1	SAT

7.	The tube sheet is SA-508 Grade 2 Class 1 (formerly SA-508 Class 2) or a low alloy steel material having similar properties. SA-508 Grade 2, Class2 (formerly SA-508 Class 2a) and SA-508 Grade 3, Class1 (formerly SA-508 Class 3) are considered similar as the analysis is bound by the properties of the SA-508 Grade 2 Class 1 (formerly SA-508 Class 2) material. SA-508 Grade A Class 2a per SU-VTM-000-38-W893-00035, SA-508 Grade A Class 2 per EDWG-000-1875E12 Sh. 1	SAT
8.	The channel head is clad with stainless steel weld material having properties similar to Type 304 stainless steel SS 304 equivalent per UFSAR Table 4.2-1	SAT
9.	Both the stub runner and the divider plate are Alloy 600 plate materials and the welds are nickel-based Inconel ERNiCr-3 or ENiCrFe-3 (commonly referred to as FM82 or FM182 respectively) Stub runner and divider plate A600, welds A82/A182 per CO-ETE-CEP-2012-1003	SAT
10.	The design and transient loads used in the report bound the similar loads in the plant SG. Design and transient loads bound the plant design basis per Table 4-2 and 4-3 comparisons.	SAT
	Evaluation of PWSCC in Tube-to-Tubesheet Welds	
1.	The tube sheet is clad on the primary side with a ERNiCr-3 weld deposit commonly referred to as FM82 which has 19 to 22%Cr or ERNiCrFe-7A (FM52M or FM52MSS or FM152) having a higher specified minimum chromium content.	N/A
2.	The Alloy 690 tubes have a minimum chromium percentage of 29.00% (This was the minimum percentage tested in the EPRI studies).	N/A
3.	The tubesheet is clad with 82 weld material or no more than the center of the tube sheet (estimated at approximately 7-inch radius) is clad on the primary side with ENiCrFe-3, commonly referred to as Filler Metal 182, or ENiCrFe-7 coated electrodes due to the manufacturing process. Note: there may be other small areas of the tubesheet that are clad with Alloy 182, which has lower chromium content. (See note 1 below)	N/A
4.	Autogenous GTAW welding has been used to join the tube and the primary face cladding. This feature establishes the weld metal dilution % used to estimate the weldment chromium percentage.	N/A

Note 1: The minimum to mean ranges expected for the Cr contents for the autogenous GTAW welds between the cladding and the Alloy 690TT tubes is 21.57 – 23.37 %Cr for tubesheet areas clad with Alloy 182 and 24.51 – 25.76 %Cr for the Alloy 82 cladding. Nearly all of the tube to tubesheet welds in the Westinghouse steam

generators fall into the Alloy 82 cladding category, but a small area in the center of the tubesheet was clad manually using the Alloy 182 filler due to geometrical considerations.

This means that the only location that can be in question is the small center portion of the tubesheet and a good bit of that area has no tubes since it is the open tube lane. So those tubes do have a slightly greater vulnerability than other locations in terms of the Cr content. However, the Cr levels of the diluted welds are still sufficiently high to impart significant resistance to initiation of PWSCC.

The residual stress state of the tubesheet cladding is largely undefined because it has received multiple post weld heat treatments, had thousands of holes drilled through the cladding and tubesheet, then had a tube inserted and welded. This is a complex set of circumstances beyond the capability of reasonable predictive methods or even meaningful measurements at a specific location for that matter.

The EPRI project analyzed the bending moments associated with the pressure differential between the primary (hot and cold sides) and the secondary sides. This pressure differential introduces a force on the bottom side of the tubesheet (clad side) that creates a compressive bending moment. This applied moment is the source of the compression in this central portion of the tubesheet rather than some complex welding residual stress. Therefore the cladding is in compression especially at the central portion of the tubesheet without uniqueness to the Model 51 generator geometric details and should be common to all. Note that the magnitude of compressive stresses is not required, but rather the compressive direction.

The report notes there could be steam generators with other small areas of the tubesheet surface that were permitted to be clad using manual welding processes, thus using 182 weld metal. However, this factor did not change the conclusions of the report and no additional inspections are recommended for these areas if they exist.

The analysis is expected to be bounding for all steam generators. Two cracking scenarios were considered to represent the limiting cases as follows:

1. Cracks propagating from the divider plate assembly through the channel head cladding and into the low alloy steel channel head material (so called Triple Point where the tube sheet, the divider plate, and the channel head intersect)

2. Cracks initiating in the tube sheet center and propagating through the tube-to-tube sheet weldments.

These are clearly bounding conditions since operation experience (even in France) has not shown evidence of cracking through the cladding into the low alloy steel shell material. Since PWSCC is not a valid assumption with carbon steel, the analysis has considered cyclic fatigue to propagate a hypothetical crack coming from a PWSCC that developed in the A-600 divider plate or FM182 used to tie the cladding material to any nickel base deposit. This condition has not been observed nor is it expected to occur. The assumption was required to facilitate a fracture mechanics analysis.

The transients evaluated (17 hot leg and 18 cold leg) include both heating and cooling conditions to determine the stress intensity factors needed to perform the Fracture Mechanics Analysis of the assumed cracks and are expected to bound all steam generators. Both a circumferential and an axial crack orientation were examined. Welding residual stresses, internal pressure stresses, and thermal transients were all considered. For all transients except heat-up and cool-down, the maximum or minimum pressure is added to the maximum or minimum thermal stress results, regardless of the time during which the thermal stresses are extracted. Doing so conservatively maximizes the total stress range and ΔK, and slightly increases the total crack growth.

If a plant's steam generators are not found to be bounded by the report, a plant-specific aging management plan should be developed. Alternatively, a rationale may be provided regarding why the plant-specific AMP is not required. For example, if the steam generator's divider plate assembly is not designed and manufactured in the same way as the one analyzed in this report, the reviewer could document why the analysis would still be bounding.

Enclosure 6

Attachment 3

EPRI 300200285 CYCLE ASSUMPTIONS / SPS CYCLE LIMIT DESIGN AND TRANSIENT COMPARISON TABLE (RAI B2.1.10-1)

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

EPRI 300200285 Cycle Assumptions / SPS Cycle Limit
Design and Transient Comparison Table

Table 4-2 Bounding Thermal Transients – Hot Leg Side

Description	Time, sec	T, °F	P, psia	Cycles	h, Btu/hr-ft²-°F	SPS CLB cycles	SPS Reference
Plant Heat-up	0	70	400	200	2885.3	200 at 100F/hr	SLRA Table 4.3.1-1
	17172	547	2250		6132.7		
Plant Cool-down	0	547	2250	200	6132.7	200 at 100 F/hr	SLRA Table 4.3.1-1
	17172	70	400		2885.3		
Plant Loading	0	547	2250	18300	6132.7	18300 at 5%/min	SLRA Table 4.3.1-1
	1200	621.9	2250		6024.0		
Plant Unloading	0	621.9	2250	18300	6024.0	18300 at 5%/min	SLRA Table 4.3.1-1
	1200	547	2250		6132.7		
Small Step Load Increase	0	621.9	2250	2000	6024.0	2000 (10% power)	SLRA Table 4.3.1-1
	50	616.9	2185		6019.8		
	180	625.9	2315		6024.0		
	300	629.9	2280		6024.0		
Small Step Load Decrease	0	621.9	2250	2000	6024.0	2000 (10% power)	SLRA Table 4.3.1-1
	30	626.9	2325		6024.0		
	150	619.9	2175		6019.8		
	300	613.9	2240		5991.1		

EPRI 300200285 Cycle Assumptions / SPS Cycle Limit Design and Transient Comparison Table

Table 4-2 Bounding Thermal Transients – Hot Leg Side

Description	Time, sec	T, °F	P, psia	Cycles	h, Btu/hr-ft²-°F	SPS CLB cycles	SPS Reference
Large Step Load Decrease	0	621.9	2250	200	6024.0	200 (100% to 50%)	SLRA Table 4.3.1-1
	60	626.9	2350		6033.3		
	480	578.9	1975		6062.0		
	1200	542.9	2210		6146.1		
Feedwater Cycling @ Hot Standby	0	621.9	2250	25000	6024.0	Note 1	Note 1
	720	594.9	2225		5991.8		
	3960	626.9	2280		6024.0		
	4500	621.9	2250		6024.0		
Loss of Load	0	621.9	2250	80	6024.0	80 (>15%)	SLRA Table 4.3.1-1
	26	647.9	2550		6053.5		
	60	583.9	1710		6062.0		
Loss of Power	0	621.9	2250	40	6024.0	40	SLRA Table 4.3.1-1
	129	597.9	2070		1653.4		
	2700	641.9	2500		366.2		
	9720	602.9	2300		361.0		
Loss of Flow	0	621.9	2250	80	6024.0	80 (one loop)	SLRA Table 4.3.1-1
	15	627.9	2220		6024.0		
	25	551.9	2100		6116.7		

EPRI 300200285 Cycle Assumptions / SPS Cycle Limit Design and Transient Comparison Table

Table 4-2 Bounding Thermal Transients – Hot Leg Side

Description	Time, sec	T, °F	P, psia	Cycles	h, Btu/hr-ft²-°F	SPS CLB cycles	SPS Reference
	50	506.9	1950		6263.3		
	140	525.9	1875		6201.4		
Reactor Trip	0	621.9	2250	400	6024.0	400 (from full power)	SLRA Table 4.3.1-1
	20	566.9	1980		6067.9		
	40	549.9	1890		6132.7		
	100	543.9	1870		6146.1		
Turbine Roll Test	0	547	2250	10	6132.7	Note 2	Note 2
	1680	475	1920		6181.1		
Primary Side Hydro Test (Shop)*		70	15	5	NA	5 (3107 psig at 100F)	SLRA Table 4.3.1-1
		250	3122				
		70	15				
Primary Side Hydro Test (Field)*		400	2250	50	NA	40 (2485 psig at 400F)	SLRA Table 4.3.1-1
		547	2500				
		400	2250				
Primary-to-Secondary Leak Test*		70	15	90	NA	Note 3	Note 3
		547	2265				
		70	15				
Feed Line Break		676.8	2650	1	NA	1 (DBE addressed in UFSAR Ch. 14)	UFSAR 14.2.11

* It is assumed that each hydro/leak test includes a heat-up/pressurization, a steady state and then a cool- down/depressurization. The heat-up/cool-down rate is assumed to be slow enough so as to not create transient thermal stresses, only steady-state stresses. Therefore, only the initial, steady state and end conditions are listed, and no heat transfer coefficients need be applied.

EPRI 300200285 Cycle Assumptions / SPS Cycle Limit Design and Transient Comparison Table

Table 4-3 Bounding Thermal Transients – Cold Leg Side

Description	Time, sec	T, °F	P, psia	Cycles	h, Btu/hr-ft²-°F	SPS CLB cycles	SPS Reference
Plant Heat-up	0	70	400	200	2885.3	200 at 100F/hr	SLRA Table 4.3.1-1
	17172	547	2250		6132.7		
Plant Cool-down	0	547	2250	200	6132.7	200 at 100 F/hr	SLRA Table 4.3.1-1
	17172	70	400		2885.3		
Plant Loading	0	547	2250	18300	6132.7	18300 at 5%/min	SLRA Table 4.3.1-1
	1200	552	2250		6119.7		
Plant Unloading	0	552	2250	18300	6119.7	18300 at 5%/min	SLRA Table 4.3.1-1
	1200	547	2250		6132.7		
Small Step Load Increase	0	552	2250	2000	6119.7	2000 (10% power)	SLRA Table 4.3.1-1
	60	539	2185		6181.6		
	180	550	2315		6132.7		
	300	554	2280		6119.7		
Small Step Load Decrease	0	552	2250	2000	6119.7	2000 (10% power)	SLRA Table 4.3.1-1
	50	567	2325		6070.8		

EPRI 300200285 Cycle Assumptions / SPS Cycle Limit Design and Transient Comparison Table

Table 4-3 Bounding Thermal Transients – Cold Leg Side

Description	Time, sec	T, °F	P, psia	Cycles	h, Btu/hr-ft²-°F	SPS CLB cycles	SPS Reference
	150	557	2175		6100.1		
	300	551	2240		6119.7		
Small Step Load Decrease	0	552	2250	2000	6119.7	2000 (10% power) (Duplicated row from above)	SLRA Table 4.3.1-1
	50	567	2325		6070.8		
	150	557	2175		6100.1		
	300	551	2240		6119.7		
Large Step Load Decrease	0	552	2250	200	6119.7	200 (100% to 50%)	SLRA Table 4.3.1-1
	60	567	2350		6070.8		
	480	555	1975		6119.7		
	1200	542	2210		6149.0		
Feedwater Cycling @ Hot Standby	0	552	2250	25000	6119.7	Note 1	Note 1
	720	525	2225		6204.4		
	3960	557	2280		6100.1		
	4500	552	2250		6119.7		
Loss of Load	0	552	2250	80	6119.7	80 (>15%)	SLRA Table 4.3.1-1
	30	587	2550		6046.1		
	60	566	1710		6070.8		
	100	555	1600		6119.7		

EPRI 300200285 Cycle Assumptions / SPS Cycle Limit Design and Transient Comparison Table

Table 4-3 Bounding Thermal Transients – Cold Leg Side

Description	Time, sec	T, °F	P, psia	Cycles	h, Btu/hr-ft²-°F	SPS CLB cycles	SPS Reference
Loss of Power	0	552	2250	40	6119.7	40	SLRA Table 4.3.1-1
	129	562	2070		1678.8		
	720	551	2500		370.2		
	9720	551	2300		370.2		
Loss of Flow	0	552	2250	80	6119.7	80 (one loop)	SLRA Table 4.3.1-1
	15	507	2220		6263.0		
	25	532	2100		6181.6		
	45	552	1950		6119.7		
	140	540	1875		6181.6		
Reactor Trip	0	552	2250	400	6119.7	400 (from full power)	SLRA Table 4.3.1-1
	20	545	1980		6149.0		
	40	542	1890		6149.0		
	100	542	1870		6149.0		
Turbine Roll Test	0	547	2250	10	6132.7	Note 2	Note 2
	1680	475	1920		6182.7		

EPRI 300200285 Cycle Assumptions / SPS Cycle Limit
Design and Transient Comparison Table

Table 4-3 Bounding Thermal Transients – Cold Leg Side

Description	Time, sec	T, °F	P, psia	Cycles	h, Btu/hr-ft²-°F	SPS CLB cycles	SPS Reference
Primary Side Hydro Test (Shop)*		70	15	5	NA	5 (3107 psig at 100F)	SLRA Table 4.3.1-1
		250	3122				
		70	15				
Primary Side Hydro Test (Field)*		400	2250	50	NA	40 (2485 psig at 400F)	SLRA Table 4.3.1-1
		547	2500				
		400	2250				
Primary-to-Secondary Leak Test*		70	15	90	NA	Note 3	Note 3
		547	2265				
		70	15				
Feed Line Break		676.8	2650	1	NA	Note 4	Note 4

* It is assumed that each hydro/leak test includes a heat-up/pressurization, a steady state and then a cool- down/depressurization. The heat-up/cool-down rate is assumed to be slow enough so as to not create transient thermal stresses, only steady-state stresses. Therefore, only the initial, steady state and end conditions are listed, and no heat transfer coefficients need be applied.

Note 1

This transient is not applicable. Feed water cycling at hot standby occurs when the plant is at hot-standby or no-load condition. The transient assumes that the steam generator is filled using 70°F feedwater by batch (slug) filling. Surry does not batch feed the steam generators at hot standby or no-load conditions.

Note 2
This pre-operational transient is no longer applicable. Surry does not perform main turbine roll testing that results in RCS cooldown with the reactor subcritical, or that results in cooldowns below the minimum temperature for criticality with the reactor critical. The CLB cycles for this transient remain bounding.

Note 3
This pre-operational transient is no longer applicable. Surry does not perform primary-to-secondary leak tests that heat up from Mode 5 conditions to hot zero power temperature and pressure conditions. The CLB cycles for this transient remain bounding.

Note 4
Rupture of a feedwater pipe is categorized as a Condition IV event in NUREG-0800 section 15.0. As such, the consequences of the accident are evaluated in the UFSAR, but it is an unanticipated occurrence, and has no cycle limit established.

Enclosure 7

WCAP-18258-P, "FLAW TOLERANCE EVALUATION FOR SUSCEPTIBLE REACTOR COOLANT LOOP CAST AUSTENITIC STAINLESS STEEL ELBOW COMPONENTS FOR SURRY UNITS 1 AND 2"

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