From:	Sayoc, Emmanuel
To:	"Daniel.g.stoddard@dominionenergy.com"
Cc:	"Paul Aitken"; "Eric A Blocher"; Oesterle, Eric; Wu, Angela; "Tony Banks"
Subject:	FINAL REQUESTS FOR ADDITIONAL INFORMATION FOR THE SAFETY REVIEW OF THE SURRY POWER STATION, UNITS 1 AND 2 SUBSEQUENT LICENSE RENEWAL APPLICATION (L-2018-RNW-0023/000951) – SET 1
Date:	Thursday, May 30, 2019 11:44:00 AM
Attachments:	Attachment 1 - Surry SLRA Final RAI Summary Index.pdf Attachment 2 - Surry SLRA Final RAIs Package Set 1.pdf
Importance:	High

Docket No. 50-280 and 50-281

Dear Mr. Stoddard,

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

From April 3, 2019 through May 15, 2019, the U.S Nuclear Regulatory Commission (NRC) staff sent Dominion the draft Requests for Additional Information (RAIs) for various technical review packages (TRP). Dominion subsequently informed the NRC staff that clarification calls were needed to discuss the information requested. Between April 11, 2019 through May 30, 2019, clarification calls were completed for all the draft RAIs unless Dominion declined having a call. The specific dates of the draft RAI transmittals and the RAIs clarification calls are summarized in Attachment 1. The final RAIs resulting from these calls are enclosed in Attachment 2.

Paul Aitken of your staff agreed to provide a response to these RAIs within 30 days of the date of this email. The NRC staff will be placing a copy of this email and attachments in the NRC’s ADAMS.

Sincerely,

Emmanuel Sayoc, Project Manager
License Renewal Projects Branch (MRPB)
Division of Materials and License Renewal
Office of Nuclear Reactor Regulation

Docket No. 50-280 and 50-281

Attachments:
As stated

OFFICE	PM:MRPB:DMLR	BC: MRPB:DMLR	PM: MRPB:DMLR

NAME	ESayoc	EOesterle	ESayoc
DATE	05/29/2019	05/30/2019	05/30/2019

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Surry SLRA RAI Set 1 Index

Item No	RAI Set	TRP	RAI Number	Issue	Date - Draft RAI Sent To Applicant	Date - Clarification Call	Clarification Call Attendees - Applicant	Clarification Call Attendees - NRC	Issue Date
1	1	1	B.2.1.1-1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program	05/13/2019	05/23/2019	Paul Aitken, Eric Blocher, Tom Snow	John Tsao, Emmanuel Sayoc	05/30/2019
2	1	1	B.2.1.1-4	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program	05/13/2019	05/23/2019	Paul Aitken, Eric Blocher, Tom Snow	John Tsao, Emmanuel Sayoc	05/30/2019
3	1	14	B.2.1.27-1	Buried and Underground Piping and Tanks	05/01/2019	05/14/2019	Paul Aitken, Eric Blocher, Pratt Cherry	Brian Allik, Bill Holston, Emmanuel Sayoc	05/30/2019
4	1	14	B.2.1.27-2	Buried and Underground Piping and Tanks	05/01/2019	05/14/2019	Paul Aitken, Eric Blocher, Pratt Cherry	Brian Allik, Bill Holston, Emmanuel Sayoc	05/30/2019
5	1	14	B.2.1.27-3	Buried and Underground Piping and Tanks	05/01/2019	05/14/2019	Paul Aitken, Eric Blocher, Pratt Cherry	Brian Allik, Bill Holston, Emmanuel Sayoc	05/30/2019
6	1	14	B.2.1.27-4	Buried and Underground Piping and Tanks	05/01/2019	05/14/2019	Paul Aitken, Eric Blocher, Pratt Cherry	Brian Allik, Bill Holston, Emmanuel Sayoc	05/30/2019
7	1	14	B.2.1.27-5	Buried and Underground Piping and Tanks	05/01/2019	05/14/2019	Paul Aitken, Eric Blocher, Pratt Cherry	Brian Allik, Bill Holston, Emmanuel Sayoc	05/30/2019
8	1	14	B.2.1.27-6	Buried and Underground Piping and Tanks	05/01/2019	05/14/2019	Paul Aitken, Eric Blocher, Pratt Cherry	Brian Allik, Bill Holston, Emmanuel Sayoc	05/30/2019
9	1	15	B.2.1.28-1	Internal Coatings	05/08/2019	05/17/2019	Paul Aitken, Eric Blocher, Mark Pelegrino	Brian Allik, Emmanuel Sayoc	05/30/2019
10	1	15	B.2.1.28-3	Internal Coatings	05/08/2019	05/17/2019	Paul Aitken, Eric Blocher, Mark Pelegrino	Brian Allik, Emmanuel Sayoc	05/30/2019
11	1	15	B.2.1.28-4	Internal Coatings	05/08/2019	05/17/2019	Paul Aitken, Eric Blocher, Mark Pelegrino	Brian Allik, Emmanuel Sayoc	05/30/2019
12	1	15	B.2.1.28-5	Internal Coatings	05/08/2019	05/17/2019	Paul Aitken, Eric Blocher, Mark Pelegrino	Brian Allik, Emmanuel Sayoc	05/30/2019
13	1	15	B.2.1.28-6	Internal Coatings	05/08/2019	05/17/2019	Paul Aitken, Eric Blocher, Mark Pelegrino	Brian Allik, Emmanuel Sayoc	05/30/2019
14	1	15	B.2.1.28-7	Internal Coatings	05/08/2019	05/17/2019	Paul Aitken, Eric Blocher, Mark Pelegrino	Brian Allik, Emmanuel Sayoc	05/30/2019
15	1	27	3.2.2.1.1-1	Fire Water System	04/03/2019	04/11/2019	Paul Aitken, Eric Blocher, Ed Turko, Craig Heah, John Thomas, Paul Aitken, Eric Blocher, Ed Turko, Craig Heah, John Thomas	Bill Holston, Alan Huynh, Steeve Bloom, Emmanuel Sayoc	05/30/2019
16	1	27	3.2.2.1.1-2	Fire Water System	04/03/2019	04/11/2019	Paul Aitken, Eric Blocher, Ed Turko, Craig Heah, John Thomas, Paul Aitken, Eric Blocher, Ed Turko, Craig Heah, John Thomas	Bill Holston, Alan Huynh, Steeve Bloom, Emmanuel Sayoc	05/30/2019
17	1	30	B.2.1.18-1	Fuel Oil Chemistry	04/03/2019	04/17/2019	Paul Aitken, Eric Blocher	Alex Chereskin, Emmanuel Sayoc	05/30/2019
18	1	41	B.2.1.29-1	PTN ASME Section XI, Subsection IWE AMP	04/30/2019	05/16/2019	Paul Aitken, Eric Blocher, Jim Johnson	Brian Wittick, George Wang, George Thomas, Sam Cuadrado, Emmanuel Sayoc	05/30/2019
19	1	45	B.2.1.33-1	Masonry Wall	04/30/2019	05/16/2019	Paul Aitken, Eric Blocher, Jim Johnson	Brian Wittick, George Wang, George Thomas, Sam Cuadrado, Emmanuel Sayoc	05/30/2019

20	1	48	B.2.1.36-1	Protective Coating Monitoring and Maintenance	05/15/2019	05/29/2019	Eric Blocher, Mark Pellegrino	Mat Yoder, Alex Cherskin, Angela Wu, Emmanuel Sayoc	05/30/2019
21	1	48	B.2.1.36-2	Protective Coating Monitoring and Maintenance	05/15/2019	05/29/2019	Eric Blocher, Mark Pellegrino	Mat Yoder, Alex Cherskin, Angela Wu, Emmanuel Sayoc	05/30/2019
22	1	61	B.3.2-1	X.M2 “Neutron Fluence Monitoring”	05/13/2019	05/23/2019	Paul Aitken, Eric Blocher, Delbert Horn, Chuck Tomes, Ben Mace	Dave Dijamco, Jim Medoff, Emmanuel Sayoc	05/30/2019
23	1	141	4.1-1	Time-Limited Aging Analyses (and Exemptions)	05/15/2019	05/23/2019	Paul Aitken, Eric Blocher, Delbert Horn, Chuck Tomes, Ben Mace	Dave Dijamco, Jim Medoff, Emmanuel Sayoc	05/30/2019
24	1	147.3	4.7.3-1	Leak Before Break	05/08/2019	05/20/2019	No Call Per Dominion	No Call Per Dominion	05/30/2019
25	1	147.3	4.7.3-2	Leak Before Break	05/08/2019	05/20/2019	No Call Per Dominion	No Call Per Dominion	05/30/2019
26	1	147.3	4.7.3-3	Leak Before Break	05/08/2019	05/20/2019	No Call Per Dominion	No Call Per Dominion	05/30/2019
27	1	147.3	4.7.3-4	Leak Before Break	05/08/2019	05/20/2019	No Call Per Dominion	No Call Per Dominion	05/30/2019
28	1	147.3	4.7.3-5	Leak Before Break	05/08/2019	05/20/2019	No Call Per Dominion	No Call Per Dominion	05/30/2019
29	1	147.3	4.7.3-6	Leak Before Break	05/08/2019	05/20/2019	No Call Per Dominion	No Call Per Dominion	05/30/2019
30	1	147.6	4.7.6-1	Reactor Coolant Pump Code Case N-481	05/15/2019	05/302019	Eric Blocher, Richard Eagan, James Ester, Chuck Tomes, Jeffrey Lloyd, George Dimitri, Amees Udyawar	Rovert Davis, John Tsao, Emmanuel Sayoc	05/30/2019
31	1	147.6	4.7.6-2	Reactor Coolant Pump Code Case N-481	05/15/2019	05/302019	Eric Blocher, Richard Eagan, James Ester, Chuck Tomes, Jeffrey Lloyd, George Dimitri, Amees Udyawar	Rovert Davis, John Tsao, Emmanuel Sayoc	05/30/2019

SURRY POWER STATION, UNITS 1 AND 2
Subsequent License Renewal Application (SLRA)
Request for Additional Information

(Set 1)

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 54.29(a)) is that actions have been identified and have been or will be taken with respect to managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under 10 CFR 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. In order to complete its review and enable making a finding under 10 CFR 54.29(a), the staff requires additional information in regard to the matters described below.

TRP 1: ASME XI - ISI (IWB,IWC,IWD)

RAI-B.2.1.1-1

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

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

Request:

1. Discuss whether the flaw evaluation was performed for a time period to the end of subsequent license renewal period (i.e., 80 years). If yes, discuss whether the final flaw/indication size at the end of 80 years is less than the allowable flaw size. If the flaw evaluation was not performed to the end of 80 years, provide justification.
2. Discuss whether this indication was analyzed as part of the Time Limited Aging Analysis. If not, provide justification.
3. The ASME Code, Section XI, IWB/C/D-2000 requires successive examinations for the flaws that remain in service and are dispositioned by a flaw evaluation. Discuss whether the three successive examinations have been performed on the Unit 2 reactor vessel inlet nozzle-to-shell weld region.

RAI- B.2.1.1-4

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

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

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

TRP 14: Buried and Underground Piping and Tanks

RAI B.2.1.27-1

Background:

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

1. "[t]he buried carbon steel piping of the fuel oil system for emergency electrical power system is the only buried piping that is protected by an active cathodic protection system."
2. "[t]he balance of piping and tanks within the scope of subsequent license renewal are not provided with cathodic protection. Based on soil sampling and testing, it has been determined that installation and operation of cathodic protection is not necessary."
3. "[t]he Buried and Underground Piping and Tanks program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M41, Buried and Underground Piping and Tanks."

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

1. "[c]athodic protection is supplied for reinforced concrete pipe and prestressed concrete cylinder pipe. Applicants provide justification when cathodic protection is not provided."
2. "[f]ailure to provide cathodic protection in accordance with Table XI.M41-1 may be acceptable if justified in the SLRA. The justification addresses soil sample locations, soil sample results, the methodology and results of how the overall soil corrosivity was determined, pipe to soil potential measurements and other relevant parameters.
3. If cathodic protection is not provided for any reason, the applicant reviews the most recent 10 years of plant-specific operating experience (OE) to determine if degraded conditions that would not have met the acceptance criteria of this AMP have occurred. This search includes components that are not in-scope for license renewal if, when compared to in-scope piping, they are similar materials and coating systems and are buried in a similar soil environment. The results of this expanded plant-specific OE search are included in the SLRA."

During the audit, the staff noted the following: (a) Preventive Action Category D has been selected for buried steel piping (i.e., external corrosion control is not required); (b) precast concrete water pipe will conform to American Water Works Association (AWWA) C302, "Standard for Reinforced Concrete Pressure Pipe, Noncylinder Type;" and (c) plant-specific OE indicating instances of leaks, coating degradation, and minor external degradation of buried steel piping.

Issue:

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

1. Consistent with GALL Report AMP XI.M41, specific details associated with how soil sampling and testing has demonstrated that installation and operation of cathodic

protection is not necessary was not provided. For example, the technical basis for not providing cathodic protection does not address pipe-to-soil potential measurements and other relevant parameters (e.g., external corrosion rate measurements).

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

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

Request:

1. State the specific specification for buried cementitious piping within the scope of subsequent license renewal (e.g., AWWA C302).
2. State the basis for why the balance of buried steel and cementitious piping and tanks within the scope of subsequent license renewal are not provided with cathodic protection.

RAI B.2.1.27-2

Background:

SLRA Section B2.1.27 states "[d]epending on the material, preventive and mitigative techniques include external coatings."

GALL-SLR Report Table XI.M41-1 recommends that the following are coated in accordance with the "preventive actions" program element of GALL-SLR Report AMP XI.M41: (a) buried steel, stainless steel, and cementitious components; and (b) underground steel and copper alloy components.

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

Issue:

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

Request:

1. Provide clarification regarding if the following are coated in accordance with the “preventive actions” program element of GALL-SLR Report Table XI.M41-1: (a) buried steel, stainless steel, and cementitious piping and piping components; and (b) underground steel and copper alloy piping and piping components. If all or portions of in-scope piping and piping components are not externally coated in accordance with the “preventive actions” program element of GALL SLR Report AMP XI.M41, provide justification for why external coatings are not provided.
2. State the basis for why the “poxitar or approved equal” external coating used on the buried fuel oil storage tanks is in accordance with the “preventive actions” program element of GALL-SLR Report AMP XI.M41.

RAI B.2.1.27-3

Background:

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

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

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

Issue:

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

Request:

1. State if all buried fire protection piping is externally coated with a bituminous coating. If buried fire protection piping is not externally coated with a bituminous coating, state the basis for how external coatings meet the intent of NFPA 24, Section 10.8.3.5.
2. State the basis for how backfill quality for buried fire protection piping meets the intent of NFPA 24, Section 10.9.

RAI B.2.1.27-4

Background:

SLRA Section B2.1.27 states the following:

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

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

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

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

- Table 9-3, "ANSI/AWWA C105/A21.5 Soil Corrosivity Index for Ductile Iron in Soil," provides identical guidance to AWWA C105, Table A.1, regarding indexing pH, redox potential, sulfides, and moisture. Table 9-3 provides different guidance to AWWA C105, Table A.1 regarding indexing soil resistivity.
- Table 9-4, "Soil Corrosivity Index from BPWORKS," provides specific guidance for cast iron (column three), carbon steel (column four), and stainless steel (column seven). Parameters used to determine soil corrosivity are soil resistivity, pH, redox potential, sulfides, chlorides, soil moisture, and soil bacteria. Based on these parameters, soil can be classified as mildly corrosive, moderately corrosive, appreciably corrosive, or severely corrosive.

Issue:

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

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

- EPRI Report 3002005294 provides two tables that provide guidance related to determining soil corrosivity. The SLRA did not state which one of these tables is used to determine soil corrosivity.
    - If EPRI Report 3002005294, Table 9-4 will be utilized (i.e., using column three for gray cast iron, column four for steel, and column seven for stainless steel), the SLRA did not state how "non-corrosive soil" determination was concluded because based on EPRI Report 3002005294, soil can only be classified as mildly corrosive, moderately corrosive, appreciably corrosive, or severely corrosive (i.e., there is no classification designated as "non-corrosive").
- GALL SLR Report AMP XI.M41 does not explicitly use soil corrosivity to guide inspection quantities for stainless steel. A basis was not provided for how EPRI Report 3002005294 will be used to guide inspection quantities for stainless steel.
- SLRA Section B2.1.27 states that soil sampling and testing is performed to confirm that the soil environment of components within the scope of license renewal is not corrosive for the installed material types. The SLRA did not state what action(s) will be taken if soil is determined to be corrosive.

<u>Request</u>:

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

RAI B2.1.27-5

<u>Background</u>:

GALL-SLR AMP XI.M41 states the following:

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

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

Issue:

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

Request:

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

RAI B2.1.27-6

Background:

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

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

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

Issue:

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

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

Request:

1. State the basis for why the effectiveness of the cathodic protection will be verified every five years when utilizing the 1 mpy and 100 mV minimum polarization cathodic protection acceptance criteria.
2. Provide clarification regarding how the impact of significant site features and local soil conditions will be factored into placement of the probes and use of probe data.

References:

- AWWA C105, “Polyethylene Encasement for Ductile-Iron Pipe Systems.” Denver, Colorado: American Water Works Association. 2010.
- AWWA C302, “Reinforced Concrete Pressure Pipe, Noncylinder Type.” Denver, Colorado: American Water Works Association. 2011.
- EPRI Report 3002005294, “Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants.” Palo Alto, California: Electric Power Research Institute. November 06, 2015.
- NFPA 24, “Standard for the Installation of Private Fire Service Mains and Their Appurtenances.” Quincy, Massachusetts: National Fire Protection Association. 2010.
- NFPA 25, “Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems, 2011 Edition.” Quincy, Massachusetts: National Fire Protection Association. 2011.

TRP 15: Internal Coatings / Lining

RAI B2.1.28-1

Background:

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

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

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

Updated Final Safety Analysis Report (UFSAR) Table 4.1-3, "Pressurizer and Pressurizer Relief Tank Design Data," states that the pressurizer relief tank has a normal water temperature of 120 degrees F and a design temperature of 340 degrees F. In addition, UFSAR Section 4.2.2.5, "Pressurizer Relief Tank," states the following:

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

Issue:

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

Request:

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

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

RAI B.2.1.28-3

Background:

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

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

Issue:

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

Request:

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

RAI B2.1.28-4

Background:

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

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

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

> If a baseline has not been previously established, baseline coating/lining inspections occur in the 10-year period prior to the subsequent period of extended operation. Subsequent inspections are based on an evaluation of the effect of a coating/lining failure on the in-scope component's intended function, potential problems identified during prior inspections, and known service life history. Subsequent inspection intervals are established by a coating specialist qualified in accordance with an ASTM

International standard endorsed in Regulatory Guide (RG) 1.54. However, inspection intervals should not exceed those in Table XI.M42-1, “Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers.”

Issue:

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

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

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

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

Request:

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

RAI B2.1.28-5

Background:

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

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

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

Issue:

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

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

Request:

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

RAI B2.1.28-6

Background:

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

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

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

Issue:

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

Request:

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

RAI B2.1.28-7

Background:

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

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

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

Issue:

It appears that based on the plant-specific OE, the component cooling heat exchangers are inspected more frequently than the guidance provided in GALL-SLR Report Table XI.M42-1, "Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers. Given that the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program will be consistent with GALL-SLR Report AMP XI.M42, the frequency of inspections of the component cooling heat exchangers could exceed the annual inspection interval because the frequency of inspections is not reflected in the current licensing basis. There is no basis for why the annual inspections of the component cooling heat exchangers is not reflected in the current licensing basis for the SPEO.

Request:

State the basis for why the annual inspections of the component cooling heat exchangers is not reflected in the current licensing basis for the SPEO.

TRP 27: Fire Water System

RAI 3.2.2.1.1-1

Background:

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

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

- "[t]he air-indoor uncontrolled environment is assigned to components that are uninsulated, or not exposed to condensation."
- "[c]racking of copper alloy >15% Zn in air is not expected in the absence of wetting and ammonia contaminants, which are not present in the air-indoor uncontrolled environment."

Issue:

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

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

Request:

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

RAI 3.2.2.1.1-2

Background:

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

1. SLRA Table 3.3-1, item 3.3.1-178, states that there are no in-scope fiberglass piping and piping components exposed to concrete in the Auxiliary Systems. However, UFSAR Section 9.10.4.18 states that there is fiberglass piping in mechanical equipment room number 4 (MER-4).
2. SLRA Table 3.3-1, item 3.3.1-184, states that there are no in-scope PVC piping, piping components or tanks exposed to concrete in the auxiliary systems. However, UFSAR Table 11.2-1, Waste Processing System Design Data," states that some portions of the liquid waste reverse osmosis unit are constructed of PVC. SLRA Section 2.3.3.23, states that some portions of the liquid waste system are in-scope.
3. SLRA Table 3.1-1, item 3.1.1-105, states that loss of material of steel with an external environment of concrete is not applicable to components in the reactor coolant system. SLRA Section 3.1.2.2.15 states that the steel neutron shield tanks are the only steel components exposed to concrete in the reactor coolant system. SLRA Table 3.1-1, item 3.1.1-115, states that there are no stainless steel components exposed to concrete in the reactor coolant system. However, UFSAR Section 4.1.2.9, "Reactor Coolant Pressure Boundary Surveillance," states, "[t]he reactor arrangement within the containment provides sufficient space for inspection of the external surfaces of the reactor coolant piping, except for the area of pipe within the primary shielding concrete."
4. SLRA Section 3.2.2.2.9 states, "[t]he concrete exposed stainless steel piping aligned to [item 3.2.1-091] is embedded within interior concrete at the containment sump and is not potentially exposed to groundwater. There are no aging effects identified that require aging management." SLRA Table 3.2.2-4 plant specific note 8 states, "[s]uction piping embedded in concrete from the containment sump is not exposed to groundwater, and has no aging effects requiring management." However, UFSAR Table 6.3-3 states that there is an outside recirculation spray pump (cited in SLRA Table 3.2-2) set in concrete. SLRA Table 3.2.2-2 includes the recirculation spray pump casing but does not cite concrete as an applicable environment.
5. SLRA Table 3.2.1, item 3.3.1-146, states that there are no in-scope stainless steel underground piping, piping components, and tanks in the auxiliary systems. However, UFSAR Section 9.10.2.3.2 states that the technical support center charcoal filter units are located in a service building vault. In addition, UFSAR Section 9.10.4.3 states that there are containment penetration vaults and UFSAR 9.10.4.7 states that there are outside containment penetration vaults.

<u>Issue</u>:

1. While UFSAR Section 9.10.4.18 does not conflict with item 3.3.1-178, it could be possible that the fiberglass piping in MER-4 penetrates the concrete floor.
2. While UFSAR Table 11.2-1 does not conflict with item 3.3.1-184, it could be possible that there could be PVC piping that penetrates the concrete floor
3. While UFSAR Section 4.1.2.9 does not conflict with items 3.1.1-105 and 3.1.1-115, it could be possible that there are other steel components and stainless steel components exposed to concrete in the vicinity of the primary shielding concrete.
4. While UFSAR Table 6.3-3 does not conflict with SLRA Section 3.2.2.2.9 or Table 3.2.2-2, it could be possible that the recirculation spray pump casing is exposed to concrete. In addition, given the pump's location, it is possible that the concrete could be exposed to ground water.

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

Request:

1. Confirm that there are no in-scope fiberglass piping and piping components exposed to concrete in the auxiliary systems.
2. Confirm that there are no in-scope PVC piping and piping components exposed to concrete in the auxiliary systems.
3. Confirm that there are no steel components other than the neutron shield tanks nor stainless steel components exposed to concrete in the reactor coolant system.
4. State whether the recirculation spray pump casing is exposed to concrete. If it is exposed to concrete, state whether the concrete could be exposed to ground water.
5. Confirm that there are no in-scope stainless steel underground piping, piping components, and tanks in the auxiliary systems.

TRP 30: Fuel Oil Chemistry

RAI B.2.1.18-1

Background:

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

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

Issue:

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

Request:

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

TRP 41: ASME Section XI, Subsection IWE

B2.1.29-1

Background:

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

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

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

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

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

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

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

temperature, pressure, and design earthquake cycles since all six conditions were shown to be satisfied.

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

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

Issue:

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

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

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

Request:

1. For each containment pressure-retaining boundary component to which the program exception applies based on the fatigue waiver assessment performed as stated in the SLRA Change Notice 2, provide in SLRA Section 4.6 (and related UFSAR supplement) a summary of the fatigue waiver assessment with results, transients considered, etc., and TLAA disposition that would demonstrate how the component met, for the

subsequent period of extended operation, the six criteria for fatigue waiver stipulated in ASME Code Section III, Subsection N-415.1, 1968 edition.

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

    a. provide the technical bases for the exception consistent with the fatigue waiver criteria in ASME Code Section III, Subsection N415.1, "Vessels Not Requiring Analysis for Cyclic Operation," that would demonstrate that the containment liner fatigue waiver analysis in SLRA Section 4.6.1 and its conclusion is applicable to each of the components to which the proposed program exception is intended to apply, or that the fatigue waiver criteria are individually met for each of these components;
    b. OR, in lieu of the exception, credit appropriate 10 CFR 50 Appendix J Type B local leak rate tests capable of detecting cracking due to cumulative fatigue damage from cyclic loading for each of the components to which the program exception is intended to apply .

TRP 45: Masonry Wall Program

RAI B.2.1.33-1

Background:

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

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

Issue:

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

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

Request:

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

TRP 48 – Protective Coating Monitoring and Maintenance

RAI B.2.1.36-1

Background:

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

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

Issue:

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

Request:

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

RAI B.2.1.36-2

Background:

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

Guide (RG) 1.54, “Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants.”

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

Issue:

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

Request:

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

TRP 61: Neutron Fluence Monitoring Program, GALL X.M2

RAI B3.2-1

Background:

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

Issue:

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

Request:

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

TRP 141: Identification of Time-Limited Aging Analyses, TLAA 4.1

RAI 4.1-1

Background:

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

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

Issue:

The exemption granting permission for use of Code Case N-514 may qualify as a regulatory exemption that meets the criteria in 10 CFR 54.21(c)(2) because: (a) the exemption was granted on October 31, 1995, in accordance with the requirements in 10 CFR 50.12,

(b) selection of the pressure lift and system enable temperature setpoints for the LTOP systems using the Code Case methodology may be dependent on the results of the adjusted reference temperature analysis (i.e., 1/4T RT_{NDT} analysis) or pressure-temperature analyses for the facility (which are TLAAs), and (c) application of the Code Case may have been used for or carried over as the basis for the current LTOP system setpoints for 48 effective full power years (i.e., the exemption remained in effect for the establishment of the current LTOP setpoints).

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

TRP 147.3: Leak-Before-Break

RAI 4.7.3-1

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.

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

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

Issue:

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

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

Request:

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

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

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

RAI 4.7.3-2

Background:

SLRA Section 4.7.3 addresses a TLAA on leak-before break (LBB) for the reactor coolant system (RCS) primary loop. Dominion (applicant) indicated the LBB analysis for 80 years of operation is documented in WCAP-15550, Revision 2. Section 7 of WCAP-15550, Revision 2

includes the elastic-plastic fracture mechanics analysis based on local failure mechanism to determine crack stability as part of the LBB analysis.

Issue:

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

Request:

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

RAI 4.7.3-3

Background:

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

Issue:

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

Request:

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

RAI 4.7.3-4

Background:

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

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

Issue:

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

Request:

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

RAI 4.7.3-5

Background:

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

Issue:

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

Request:

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

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

RAI 4.7.3-6

Background:

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

Issue:

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

Request:

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

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

TRP 147.6: Reactor Coolant Pump Code Case N-481

RAI 4.7.6-1

Background:

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

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

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

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

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

Issue:

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

Request:

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

RAI 4.7.6-2

Background:

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

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

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

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

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

<u>Issue:</u>

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

<u>Request:</u>

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