VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

October 14, 2019

10 CFR 50
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10 CFR 54

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

Serial Nos.: 19-385
NRA/DEA: R2
Docket Nos.: 50-280/281
License Nos.: DPR-32/37

VIRGINIA ELECTRIC AND POWER COMPANY
SURRY POWER STATION (SPS) UNITS 1 AND 2
SUBSEQUENT LICENSE RENEWAL APPLICATION
FIRST 10 CFR 54.21(b) ANNUAL AMENDMENT AND
SUPPLEMENT TO SUBSEQUENT LICENSE RENEWAL APPLICATION
CHANGE NOTICE 4

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.

10 CFR 54.21(b) requires Dominion to report changes to the current licensing basis (CLB) that materially affect the contents of the subsequent license renewal application (SLRA), including the UFSAR supplement. These changes are required to be submitted each year and at least 3 months prior to the scheduled completion of the LRA review by the NRC.

Dominion has completed the annual review and concluded that there are three changes that are considered to materially affect the contents of the SPS SLRA. Enclosure 1 provides the descriptions of these CLB changes.

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Change Notice 4, provided in Enclosure 2, includes additional information and clarification of four topics that require an SLRA supplement to assist the NRC staff with their review of requests for information that were previously submitted. A description of each topic and the affected SLRA Section are included in Enclosure 2.

Enclosure 3 contains SLRA mark-ups that are a result of the CLB changes and Change Notice 4 described in Enclosures 1 and 2, respectively.

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 and Fleet Support

COMMONWEALTH OF VIRGINIA)
)
COUNTY OF HENRICO)

The foregoing document was acknowledged before me, in and for the County and Commonwealth aforesaid, today by Mark D. Sartain, who is Senior Vice President - Nuclear Operations and 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 14th day of October, 2019.

My Commission Expires: August 31, 2023

GARY DON MILLER
Notary Public
Commonwealth of Virginia
Reg. # 7629412
My Commission Expires August 31, 2023

Notary Public

Commitments made in this letter: None

Enclosures:

1. Current Licensing Basis Changes that Impact the SLRA – First 10 CFR 54.21(b) Annual Amendment
2. Topics that Require a SLRA Supplement – Change Notice 4
3. SLRA Mark-ups – First 10 CFR 54.21(b) Annual Amendment and Change Notice 4

cc: (w/o Enclosures except *)

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Enclosure 1

CURRENT LICENSING BASIS CHANGES THAT IMPACT THE SLRA
FIRST 10 CFR 54.21(b) ANNUAL AMENDMENT

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

CURRENT LICENSING BASIS CHANGES THAT IMPACT THE SLRA FIRST 10 CFR 54.21(b) ANNUAL AMENDMENT

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.

10 CFR 54.21 requires Dominion to report changes to the current licensing basis (CLB) that materially affect the contents of the subsequent license renewal application (SLRA), including the UFSAR supplement. These changes are required to be submitted each year and at least 3 months prior to the scheduled completion of the LRA review by the NRC.

Dominion has completed the annual review and concluded that the following three changes are considered to materially affect the contents of the SPS SLRA and require the SLRA to be supplemented:

1. Fire Protection System Component Replacements
2. MRP-227 Rev 1 NRC Safety Evaluation and MRP 2019-009 in Appendix C
3. Revision of TLAA Reference Documents

This enclosure includes a description of each change and identifies the affected portion(s) of the SLRA associated with each change. Revisions to the SLRA are provided in Enclosure 3.

Change #1 - Fire Protection Component Replacements

As a result of recent operating experience, two sections of buried gray cast iron fire water pipe internally lined with a cementitious coating were replaced with ductile iron pipe internally lined with a cementitious material. Operating Experience Item #14 was added to the *Fire Water System* program (B2.1.16) to describe the fire protection system buried piping operating experience. In addition, a gray cast iron fire protection system valve in the Turbine Building was replaced with a ductile iron valve due to obsolescence of the original valve.

When reviewing item equivalency evaluations for the first annual amendment, it was identified that the fire protection halon/$C0_2$ subsystems contain elastomer flexible hoses that are subject to aging management review. The program description for the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program (B2.1.25) and UFSAR Supplement in SLRA Section A1.25 were revised to include a gas environment for internal surface inspections.

SLRA Changes

Based on the above discussions, SLRA Section A1.25, Section B2.1.16, Section B2.1.25, and Table 3.3.2-34, are supplemented, as shown in Enclosure 3.

Change #2 - Incorporation of MRP-227, Rev. 1 NRC Safety Evaluation and MRP 2019-009

The Final NRC Safety Evaluation for MRP-227, Revision 1, dated April 25, 2019, and related MRP reactor internals inspection guidance, provide the basis for changes to the *PWR Vessel Internals* program (B2.1.7) and Appendix C (MRP-227-A Gap Analysis). Additional guidance from MRP 2019-009 (PWR Core Barrel and Core Support Barrel Inspection Requirements) is also included for core barrel weld inspections of the middle axial weld (MAW) and the lower axial weld (LAW). As a result, the *PWR Vessel Internals* program (B2.1.7) enhancements have been revised to include the following inspection guidance:

- Lower Girth Weld (Primary Component) – MRP 2019-009

  A one-time enhanced visual (EVT-1) examination of the core barrel middle axial weld (MAW) and lower axial weld (LAW) will be performed during the sixth inservice inspection interval (i.e., a "50-year inspection") no later than six months prior to the subsequent period of extended operation. The examination will include coverage for 100% of the accessible weld lengths from the core barrel OD and ¾" of base metal on each side the weld AND a vertical zone on each side of the inaccessible portion of the barrel containing the known location of the axial weld. Each vertical zone shall be a minimum of 3/4" wide and cover the full distance parallel to the inaccessible height of the weld.

- Baffle-Former Assembly (Primary Component) – MRP-227, Rev. 1

  Clarified the program enhancement with the following primary component inspection table note:

  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 visual (VT-3) inspection 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 (MRP 2018-002, Item 3.b) 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.

  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

- Lower Flange Weld and Upper Girth Weld (Expansion Components) - MRP-227, Rev. 1

  MRP-227 Rev 1 added the lower flange weld (LFW) and upper girth weld (UGW) to the expansion category as a link from the upper flange weld (UFW). A note was added to examination coverage to indicate a minimum 75% coverage unless access limitations prevent examination of more than 50% of the weld. Enhancement #9 has been revised to clarify the examination requirements for the LFW and UGW. As a result, Enhancement #16(c) for the LFW has been deleted.

- Continuous Section Sheaths and C-tubes (Expansion Component) – WCAP-17451-P, Revision 2

  Procedures will be revised for contingency tasks to inspect the control rod guide tube (CRGT) continuous section sheaths and C-tubes in accordance with the requirements of WCAP-17451-P, Revision 2.

<u>SLRA Changes</u>

Based on the above, SLRA Table A4.0-1 item 7, Enhancements 7, 9, 12(b) and 16, Section B2.1.7 and Appendix C are supplemented, as shown in Enclosure 3 to incorporate the program enhancements noted above and associated Appendix C changes.

Change #3 - Revision of TLAA Reference Documents

<u>BAW-2178 Supplement 1P-A and BAW-2192 Supplement 1P-A</u>

BAW-2192 (Proprietary), Supplement 1, Revision 0, "Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W Owners Reactor Vessel Working Group for Levels A & B Service Loads Topical Report," and BAW-2178 (Proprietary), Supplement 1, Revision 0, "Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W Owners Reactor Vessel Working Group for Levels C & D Service Loads Topical Report," have been revised to incorporate the final NRC Safety Evaluation issued December 7, 2018 (ML1818332A376).

Based on the above document revisions, SLRA Section 4.2.2 and Section 4.8 are supplemented, as shown in Enclosure 3, to reference BAW-2178 and BAW-2192 as NRC approved Topical Reports,

<u>CN-PAFM-16-55</u>

Since submittal of the SLRA, CN-PAFM-16-55, Revision 1, "Transient Basis for Surry Units 1 and 2 80 Year License Renewal Evaluations," has been issued to clarify CLB transients and transient counts. No changes were made to the projected cycles from Revision 0. All statements in the SLRA reflect correct transient information.

<u>SLRA Changes</u>

Based on the above, SLRA Section 4.8 is supplemented, as shown in Enclosure 3 to reference CN-PAFM-16-55, Revision 1.

Enclosure 2

TOPICS THAT REQUIRE A SLRA SUPPLEMENT – CHANGE NOTICE 4

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

TOPICS THAT REQUIRE A SLRA SUPPLEMENT – CHANGE NOTICE 4

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.

This enclosure, Change Notice 4, includes additional information and clarification of four topics that require an SLRA supplement to assist the NRC staff with their review of requests for information that were previously submitted. Change Notice 4 includes a description of the following four topics and identifies the affected portion(s) of the SLRA associated with each topic:

1. ASME Code Case N-871 Changes in the Open-Cycle Cooling Water program
2. Inspection of Buried Surfaces for the 96-Inch Circulating Water Piping
3. Deletion of Coated Buried Component Inspection Exclusion
4. Addition of Cathodic Protection For Buried Carbon Steel Piping

Revisions to the SLRA are provided in Enclosure 3.

Change #1 - ASME Code Case N-871 Changes in the Open-Cycle Cooling Water program

ASME Code Case N-871 will be clarified by the ASME Code Committee to reflect the items indicated below and they will be incorporated into applicable station procedures:

- Section V-2500: Accessible surfaces of the CFRP lining at each terminal end shall be volumetrically examined using the same or demonstrated equivalent volumetric method as used for preservice examination, and recorded in accordance with 5250(a) and 5350 between three 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.
- Section 5250(a)(1): Acoustic tap examination of terminal ends using procedure and personnel qualified in accordance with Mandatory Appendix VI and 5400, and demonstrated to the ANII as capable of detecting and sizing delaminations and voids in any composite or bonding layer with dimensions equal to or less than those permitted by 4390(b)(3).
- Section 5211(d) (in part): Consideration shall be given to the impact of in-situ ambient noise levels on application of the procedure and qualification of procedures and personnel.

Prior to installation of the existing CFRP lining, the exposed metallic substrate was ultrasonically examined to confirm the minimum wall thickness requirements specified in the design documents were met. There is no exposed metallic substrate on the interior of the CFRP lined circulating water system piping. Exposed metallic substrate on the exterior of the CFRP lined circulating water system piping is managed by the *External Surfaces Monitoring of Mechanical Components* program (B2.1.23).

<u>SLRA Changes</u>

Based on the above discussion, SLRA Table A4.0-1, Item 11, Enhancements 9, 10 and 11 and Section B2.1.11 are supplemented as shown in Enclosure 3.

Change #2 - Inspection of Buried Surfaces for the 96-Inch Circulating Water Piping

A one-time inspection of the below-grade concrete of an adjacent structure located in the vicinity of the 96-inch cementitious circulating water (CW) piping between the High Level Intake Structures and the Turbine Building with similar material and environmental properties will be performed. The one-time inspection will be performed using the *Buried and Underground Piping and Tank* program (B2.1.27). Additional considerations related to concrete aging, concrete inspections and groundwater monitoring will be informed using insights from the Structures Monitoring program (B2.1.34).

Cementitious 96-inch Circulating Water Piping Configuration

Cooling water to the Unit 1 and Unit 2 main condensers and service water systems are supplied by the 96-inch CW piping.

The piping for each unit consists of four 96-inch (inside diameter) concrete water supply pipes that are sloped from the intake structure to the respective main condenser based on the gravity feed design of the unit. The length of each concrete pipe, including the steel pipe adapters, is approximately 130 feet, with the steel adapters being 9.5 inches. The concrete pipe wall thickness is nine inches, reinforced with rebar longitudinally and circumferentially on both the inside face and the outside face. The maximum circumferential spacing of the longitudinal reinforcing bars is 42 inches. The minimum clear spacing between the circumferential reinforcing bars is 1.25 inches. The maximum center-to-center spacing of the circumferential bars is four inches. This spacing provides a higher degree of crack prevention to ensure the water-tightness of the pipe. The size of the reinforcing bars is not available. The frost depth is 18 inches and the 96-inch CW piping has a minimum of 16 feet of soil cover.

The water volume and static head of the intake canal provides the water inventory necessary to meet the intended function of the service water system. The circulating water and emergency service water pumps maintain canal level during normal and emergency operation. In the event of a breach of the intake canal, Abnormal Procedures will be initiated to address the breach. Upon identifying the breach, necessary actions, including starting additional circulating pumps (as required), safe-shutdown of the units and isolating non-essential loads to maintain canal inventory will be performed to ensure intended functions are maintained.

Aging Management (Non-Aggressive Groundwater/Soil Environment)

For non-aggressive environments, the *Structures Monitoring* program (B2.1.34):

- Evaluates the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation in accessible areas, and
- Examines samples of the exposed portions of the below grade concrete, when excavated for any reason.

Aging Management (Aggressive Groundwater/Soil Environment)

For aggressive groundwater/soil environments or when concrete 96-inch CW piping and structures have experienced degradation, corrective actions accounting for the extent of the degradation experienced will be implemented to manage the concrete aging. Corrective actions may include evaluations, determination of impact on other concrete structures or pipes, destructive testing, or focused inspections of representative accessible (leading indicator) or below-grade inaccessible concrete structural elements exposed to aggressive groundwater/soil.

Aging Effects Managed

The aging effects of cracking and loss of material are managed for the 96-inch CW piping using applicable portions of the *Structures Monitoring* program (B2.1.34). The *Structures Monitoring* program (B2.1.34) also manages the same aging effects of the groundwater/soil environment for the High Level Intake Structure, Fire Pump House and the Turbine Building. This is consistent with initial license renewal commitments that managed the concrete CW pipe as part of the intake structures group that also included the High Level Intake Structure, Discharge Tunnel and Seal Pit structures.

Additionally, a one-time inspection of the below-grade concrete of an adjacent structure located in the vicinity of the 96-inch cementitious CW piping between the High Level Intake Structures and the Turbine Building with similar material and environmental properties will be performed. The one-time inspection will be performed using the *Buried and Underground Piping and Tank* program (B2.1.27).

Concrete Comparison

The 96-inch concrete CW pipe was specified to conform to AWWA Standard C302. Table 1 contains a comparison between AWWA C302 concrete standards and UFSAR concrete standards for SPS concrete structures (UFSAR Section 15.3.1).

Table 1 - Comparison of Concrete Components

	96-inch CW Pipe	**SPS Concrete Structures**
Cement	ASTM C150	ASTM C150
Fine Aggregate	ASTM C33	ASTM C33
Coarse Aggregate	ASTM C33	ASTM C33
Water	Free from injurious amounts of oils, acids, strong alkalis, salts, vegetable matter	Free from injurious amounts of oils, acids, alkalis, salts, organic materials
Air Entrainment	N/A[1]	ASTM C260
Water/Cement Ratio	0.45	0.46
Reinforcing Steel	ASTM A615	ASTM A615
Minimum Specified 28-day Strength	4,500 psi	3,000 psi[2]

1 Air entrainment is not required to manage freeze-thaw effects for the CW pipe due to its location well below the frost line.

2 Per UFSAR Section 15A.3.4, a concrete inspection program was subsequently performed on various locations throughout the plant, which demonstrated with a 95% confidence level, that concrete strength was at least 4000 psi.

As demonstrated in the Table 1 above, the standards for the primary components of the concrete mix designs used to construct the 96-inch CW piping are consistent with the standards for the concrete used to construct the SPS concrete structures.

Environment Comparison

NUREG-2191, Section IX.D, groundwater/soil definition states the following:

> "Concrete subjected to a groundwater/soil environment can be vulnerable to an increase in porosity and permeability, cracking, loss of material (spalling, scaling), or aggressive chemical attack. Other materials with prolonged exposures to groundwater or moist soils are subject to the same aging effects as those systems and components exposed to raw water".

Groundwater monitoring (presented below) confirms that the groundwater in vicinity of the concrete CW piping is non-aggressive. The performance of a one-time inspection on a structure in the vicinity of the 96-inch CW piping will provide reasonable assurance of the condition of the external surfaces.

Aging Management Characteristics

Consistent with NUREG-2191, Section VII.C1, cracking and loss of material aging effects of the concrete 96-inch CW piping exposed to a groundwater/soil environment are managed by referencing and using applicable portions of the *Structures Monitoring* program (B2.1.34).

In addition to the aging effects managed, the following common aging management characteristics are provided:

- ACI 349.3R provides an acceptable basis for selection of parameters to be inspected
- Inspectors and responsible engineers are qualified consistent with ACI 349.3R
- Concrete acceptance criteria are consistent with ACI 349.3R

Acceptance Criteria

The following criteria is provided by ACI 349.3R criteria for evaluating conditions identified during visual examination of concrete surfaces:

- First-tier criteria are quantitative limits below which the condition is considered acceptable without requiring any further evaluation.
- Second-tier criteria are a set of acceptable conditions for observed degradation that has been determined to be inactive. Inactive degradation can be determined by the quantitative comparison of current observed conditions with that of prior inspections. If conditions fall between the first-tier and the second-tier criteria, and there is a high potential for progressive degradation or

propagation to occur at its present or accelerated rate, the disposition should consider more frequent evaluations of the specific structure or initial repair planning.

- Observed conditions that exceed the second-tier acceptance limits should be considered unacceptable and in need of further technical evaluation, which should consider the use of other inspection, testing, or analytical tools to obtain condition and functional information of the structure in question. At this stage of the evaluation process, re-analysis of structural capacity and behavior under degraded physical conditions is often necessary.

Observed conditions that exceed first-tier criteria are entered into the Corrective Action Program. The Responsible Civil Engineer will evaluate the conditions from the perspective of how such degradation could potentially affect the 96-inch CW pipe, should similar degradation occur on the 96-inch CW pipe. Evaluations are documented, and any further actions required are determined by the Responsible Civil Engineer, based on the conditions observed. The evaluation determines the significance of the degradation as it pertains to the CW pipe. The further evaluation required by the Corrective Action Program considers the apparent cause of the degradation, and the applicability of that cause to the CW pipe. Further actions may include additional analysis, expanded inspections, or testing (e.g., destructive testing), if warranted.

Monitoring of the Groundwater/Soil Environment

Groundwater/soil monitoring for the concrete 96-inch CW piping locations are located between the Turbine Building and the High Level Intake Structures. The groundwater/soil monitoring procedures periodically sample the following specific locations in the vicinity of the concrete 96-inch CW piping. Groundwater/soil monitoring sampling intervals do not exceed five years and evaluations account for seasonal variations:

- P22 - between the Unit 1 and Unit 2 condensate storage tanks and the Unit 1 CW inlet piping from the High Level Intake Structure
- P28 - between the Unit 1 CW inlet piping from the High Level Intake Structure and the Unit 2 CW inlet piping from the High Level Intake Structure
- P20 - between the distillate storage tank and the Unit 2 CW inlet piping from the High Level Intake Structure

Groundwater samples are monitored to confirm a non-aggressive groundwater/soil environment of pH > 5.5, chlorides < 500 ppm, and sulfates <1,500 ppm. Groundwater sample results taken in March 2019 at the three locations noted above confirm a non-aggressive groundwater/soil environment. If groundwater values increase above the established thresholds then this condition will be entered into the Corrective Action Program for further evaluation and appropriate corrective actions that may include further sampling, additional inspections, core boring and the development of a plant specific aging management program, if necessary.

The Unit 1 concrete 96-inch CW piping runs between piezometers P22 and P28; and the Unit 2 concrete 96-inch CW piping runs between piezometers P20 and P28. The distance between piezometers P22 and P28; and the distance between piezometers P20 and P28 are approximately 250 feet. Yard grade above the 96-inch CW pipe is at 26'-6". The centerline of the 96-inch CW piping varies from 29'-6" below grade to 21'-0" below grade. Groundwater level data collected in June, 2014 shows the groundwater at Piezometers P20, P22, and P28 ranging from approximately 18'-6" below grade to 16'-6" below grade.

Dominion previously submitted an enhancement to perform two soil corrosivity samples: one adjacent to the Unit 1 CW piping and another adjacent to the Unit 2 CW piping as part of the *Open Cycle Cooling Water System* program (B2.1.11) [ADAMS Accession No. ML19253B330]. This sampling will be performed on a 10-year interval consistent with the requirements in NUREG-2191, Table XI.M41-2. Data collected at each sample location will include: soil resistivity, soil consortia (bacteria), pH, moisture, chlorides, sulfates, and redox potential. In addition to evaluating each individual parameter, corrosivity of carbon steel reinforcement and concrete degradation in high sulfate and acidic environments will be evaluated.

<u>Aging Management Changes</u>

Procedure(s) will be developed to perform a one-time inspection (one excavation) for evidence of concrete aging (below-grade) associated with either the Unit 1 or Unit 2 High Level Intake Structures, or the south side of the Turbine Building, or the Fire Water Pump House. The one-time inspection will require a minimum of 50 ft^2 below the frost line of the buried surfaces of the selected structure. The procedure will require that as a surrogate location, the evaluation of the one-time inspection results also include evaluation of the acceptability of the eight inaccessible 96-inch CW pipes located between the High Level Intake Structures and the Turbine Building using the guidance in ACI 349.3R.

<u>SLRA Changes</u>

Based on the above, SLRA Table 3.3.1, Item 3.3.1-103, Table 3.3.2-5, Table A4.0-1, Items 11 and 27, Section B2.1.11 and Section B2.1.27 are supplemented as shown in Enclosure 3.

Change #3 - Deletion of Coated Buried Component Inspection Exclusion

Due to plant operating experience with external coatings on buried components, the *Selective Leaching* program (B2.1.21) inspection exclusion has been deleted for buried components that are susceptible to selective leaching and are coated consistent with the *Buried and Underground Piping and Tanks* program (B2.1.27). As a result, externally coated buried components that are susceptible to selective leaching are included in program sample plans and inspected consistent with the *Selective Leaching* program (B2.1.21) aging management requirements.

SLRA Changes

Based on the above, SLRA Section B2.1.21 is supplemented, as shown in Enclosure 2 to delete the *Selective Leaching* program (B2.1.21) inspection exclusion for buried components that are externally coated.

Change #4 - Addition of Cathodic Protection for Buried Carbon Steel Piping

A cathodic protection system will be installed for protection of each unit's buried carbon steel condensate system and auxiliary feedwater system piping from the emergency condensate storage tank and the emergency condensate makeup tank to the service building five years before entering the subsequent period of extended operation.

SLRA Changes

As shown in Enclosure 3, SLRA Table A4.0-1, Item 27 and Section B2.1.27 are supplemented to indicate installation of a cathodic protection system for protection of carbon steel piping in the vicinity of the structures indicated above.

Enclosure 3

SLRA MARK-UPS
FIRST 10 CFR 54.21(b) ANNUAL AMENDMENT
AND SUPPLEMENT TO PREVIOUSLY SUBMITTTED RAI RESPONSES

NOTE: To avoid confusion and comply with the Paperwork Reduction Act, necessary revisions to SLRA Tables are shown by providing a mark-up on an excerpt from the affected SLRA Table. Necessary SLRA Section revisions are shown by providing a mark-up of the entire Section.

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

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

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

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

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (circulating water condenser - channel head)	PB	Steel with internal coating	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Condensation	Loss of material (steel only); cracking (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	C, 8
			(I) Raw water	Loss of coating or lining integrity; loss of material or cracking (for cementitious coatings/linings)	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-416	3.3.1-138	A
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-400	3.3.1-127	E, 6
						VII.C1.A-414	3.3.1-139	A
Heat exchanger (circulating water condenser - tube)	PB	Titanium	(I) Raw water	Cracking (titanium only); reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-736	3.3.1-207	A, 4
			(E) Treated water	Cracking; reduction of heat transfer	One-Time Inspection (B2.1.20)	VII.C1.A-765	3.3.1-236	A, 4
					Water Chemistry (B2.1.2)	VII.C1.A-765	3.3.1-236	B, 4
Heat exchanger (circulating water condenser - tubesheet)	PB	Copper alloy with internal coating	(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, 5
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-414	3.3.1-139	A, 5
			(E) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-101	3.4.1-016	C, 5
					Water Chemistry (B2.1.2)	VIII.F.SP-101	3.4.1-016	D, 5
Piping, piping components	LB;PB	Concrete	(I) Raw water	Cracking; loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-250	3.3.1-030	B
			(E) Soil	Cracking; loss of material	~~Open-Cycle Cooling Water System (B2.1.11)~~Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-157	3.3.1-103	~~E, 9~~A

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

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	PB	Ductile iron with internal lining	(E) Soil	Loss of material	Selective Leaching (B2.1.21)	VII.G.A-02	3.3.1-072	A
					Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A
			(I) Raw water	Loss of material	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.G.A-414	3.3.1-139	A
				Loss of coating or lining integrity; loss of material or cracking	Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.G.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.G.A-415	3.3.1-140	A
Flexible hose	PB	Elastomer	(I) Gas	Hardening or loss of strength due to elastomer degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-729	3.3.1-085	A
			(E) Air-indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
				Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A

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

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	PB	Ductile iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Loss of material	Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
				Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A

Table 3.3.2-34 Plant-Specific Notes:

1. Visual inspection from the external surface of plexiglass windows of the reactor coolant pump oil collection enclosures can identify both internal and external degradation of the plexiglass.
2. Internal and external environments are such that the external surface condition is representative of the internal surface condition.
3. Flow blockage is not an applicable aging effect in this environment, or for external surfaces.
4. The Fire Water System (B2.1.16) program is used instead of the Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program to manage loss of material for internally coated carbon steel fire water storage tanks. The Fire Water System (B2.1.16) program manages degraded internal coatings consistent with NUREG-2191 Table XI.M27-1 note 4.
5. The Fire Protection (B2.1.15) program will manage aging of the external surfaces of carbon dioxide and halon system piping components.
6. Fatigue cracking of fire protection piping defects is a TLAA, evaluated in Section 4.7.5, Piping Subsurface Flaw Evaluations.

As documented in WCAP-18242-NP, the materials projected to exceed 1.0 x 10^{17} n/cm^2 (E > 1.0 MeV) at 68 EFPY are evaluated to determine their impact on USE during the proposed subsequent period of extended operation. The forgings and welds corresponding to some inlet and outlet nozzles are predicted to experience neutron fluence greater than 1.0 x 10^{17} n/cm^2 at the end of the subsequent period of extended operation. However, for conservatism all of the inlet and outlet nozzle materials are considered part of the extended beltline in the USE evaluation. The Units 1 and 2 materials include three (3) inlet nozzles, three (3) outlet nozzles, three (3) inlet nozzle to upper-shell welds, and three (3) outlet nozzle to upper-shell welds per unit. (Note: nozzle-shell and upper-shell refer to the same component and are used interchangeably).

The identification of the RV plate and weld materials is shown in Figure 4.2.2-1 for Unit 1 and Figure 4.2.2-2 for Unit 2. The material property inputs used for the RV integrity evaluations are described in this section. The initial material properties were updated from previous RV integrity evaluations per PWROG-16045-NP and WCAP-18242-NP, Appendix E, and the fluence values were updated per WCAP-18028-NP and WCAP-18242-NP, Section 2. Additionally, initial USE values are supplied in Table 4.2.2-1 and Table 4.2.2-3.

The requirements on USE for beltline materials are included in 10 CFR 50, Appendix G, which requires utilities to submit an analysis at least three years prior to the time that the USE of any RV material is predicted to drop below 50 ft-lb. Dominion has conservatively elected to perform equivalent margins analyses (EMAs) for inlet and outlet nozzle welds with Charpy USE near 50 ft-lb at the end of the subsequent period of extended operation.

Two methods can be used to predict the decrease in USE with irradiation, depending on the availability of credible surveillance capsule data as defined in Regulatory Guide 1.99. For vessel beltline materials that are not in the surveillance program or have non-credible data, the Charpy USE (Position 1.2) is assumed to decrease as a function of fluence and copper content, as indicated in Regulatory Guide 1.99. When two or more credible surveillance sets become available from the reactor, they may be used to determine the Charpy USE of the surveillance material. The surveillance data are then used in conjunction with Regulatory Guide 1.99 to predict the change in USE (Position 2.2) of the RV material due to irradiation. Per Regulatory Guide 1.99 (Revision 2), when credible data exists the Position 2.2 projected USE value should be used in preference to the Position 2.1 projected USE value. Such cases exist in Table 4.2.2-5 wherein SLR USE values in the Position 1.2 section that fall below 50 ft-lbs are not an issue because corresponding values in the Position 2.2 section are above 50 ft-lbs when considering credible surveillance data.

The 68 EFPY Position 1.2 USE values of the vessel materials can be predicted using the corresponding fluence projections (1/4T for beltline materials and surface for inlet/outlet nozzles), the copper content of the materials, and Figure 2 in Regulatory Guide 1.99.

The predicted Position 2.2 USE values are determined for the RV materials that are contained in the surveillance program by using the reduced plant surveillance data along with the corresponding fluence projection (1/4T for beltline materials and surface for inlet/outlet nozzles). The reduced plant surveillance data was obtained from Table 7-6 of BAW-2324, "Analysis of Capsule X Virginia Power Surry Unit No. 1, Reactor Vessel Material Surveillance Program" (Reference 4.8-17) for Unit 1. The reduced plant surveillance data was obtained from Table 5-12 of WCAP-16001, "Analysis of Capsule Y from Dominion Surry Unit 2 Reactor Vessel Radiation Surveillance Program" (Reference 4.8-18) for Unit 2. The surveillance data was plotted in Regulatory Guide 1.99, Figure 2 using the surveillance capsule fluence values documented in Table 2-1 of WCAP-18242-NP, for Unit 1 and Table 2-2 of WCAP-18242-NP, for Unit 2.

The projected USE values were calculated to determine if the values for Units 1 and 2 materials remain above the 50 ft-lb criterion at 68 EFPY. The projected USE values for the inlet and outlet nozzle forgings were conservatively calculated using the maximum fluence values corresponding to the lowest extent of the nozzle to shell welds. These calculations are summarized in Table 4.2.2-5 and Table 4.2.2-6.

Conclusion

For Unit 1, the limiting USE value at 68 EFPY is 32 ft-lb (see Table 4.2.2-5); this value applies to the Intermediate to Lower Shell Circumferential Weld using Position 1.2. For Unit 2, the limiting USE value at 68 EFPY is 41 ft-lb (see Table 4.2.2-6); this value applies to the Upper to Intermediate Shell Circumferential Weld using Position 1.2.

The NRC has previously approved the use of the equivalent margins analysis (EMA) BAW-2494, "Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessel of Surry Power Station Units 1 and 2 for Extended Life through 48 Effective Full Power Years" (Reference 4.8-19) to qualify all of the materials currently projected to drop below 50 ft-lb USE at 68 EFPY. These materials are identified by the notes in Table 4.2.2-1, Table 4.2.2-3, Table 4.2.2-5, Table 4.2.2-6 herein and are summarized below. The EMAs for these materials are updated for the subsequent period of extended operation under ANP-3679NP, "Low Upper-Shelf Toughness Fracture Mechanics Analysis for Surry Units 1 and 2 Reactor Vessels for Levels A & B Service Loads at 80 Years," (Reference 4.8-20) and ANP-3680NP, "Low Upper-Shelf Toughness Fracture Mechanics Analysis for Surry Units 1 and 2 Reactor Vessels for Levels C & D Service Loads at 80 Years" (Reference 4.8-21). The updated EMA is based upon the provisions outlined in ASME Code, Section XI, Appendix K. The selection of design transients for Levels C & D service loads are based on the guidance in Regulatory Guide 1.161, "Evaluation of Reactor Pressure Vessels with Charpy Upper-Shelf Energy Less Than 50 Ft-Lb." (Reference 4.8-22) and ASME Code, Section XI, Appendix K.

An EMA should be submitted three years before a material is projected to drop below 50 ft-lbs; however, no additional materials are projected to drop below 50 ft-lb USE during the subsequent period of extended operation.

The following Unit 1 and Unit 2 materials are addressed by EMAs for the subsequent period of extended operation:

Unit 1:

- Upper to Intermediate Shell Circumferential Weld, Heat # 25017 (J726)
- Intermediate Shell Longitudinal Welds L3 and L4, Heat # 8T1554
- Intermediate to Lower Shell Circumferential Weld, Heat # 72445
- Lower Shell Longitudinal Weld L1, Heat # 8T1554
- Lower Shell Longitudinal Weld L2, Heat # 299L44
- Inlet Nozzle to Shell Welds, Heat # 299L44 and # 8T1762; (Projected USE > 50 ft-lbs at 68 EFPY)
- Outlet Nozzle to Shell Welds, Heat # 8T1762 and # 8T1554B; (Projected USE > 50 ft-lbs at 68 EFPY)

Unit 2:

- Upper to Intermediate Shell Circumferential Weld, Heat # 4275 (J737)
- Intermediate Shell Longitudinal Welds L3 and L4, Heat # 72445
- Intermediate Shell Longitudinal Weld L4, Heat # 8T1762
- Intermediate to Lower Shell Circumferential Weld, Heat # 0227
- Lower Shell Longitudinal Weld L1 and L2, Heat # 8T1762
- Inlet Nozzle to Shell Welds, Heat # 8T1762; (Projected USE not projected > 50 ft-lbs at 68 EFPY)
- Outlet Nozzle to Shell Welds, Rotterdam Weld; (Projected USE > 50 ft-lbs at 68 EFPY)

An EMA has been completed for the Unit 1 and Unit 2 Inlet and Outlet Nozzle to Shell Welds even though these materials are not projected to drop below 50 ft-lbs through 68 EFPY using the methods herein. The inlet and outlet nozzle welds are the only materials included in ANP-3679NP and ANP-3680NP that were not previously addressed by EMA. The EMA is applicable to the

Units 1 and 2 nozzle to shell welds which exceed the fluence criterion of 1.0 x 10^{17} n/cm^2 before 68 EFPY. These materials include those listed below.

- Unit 1 Outlet Nozzle 1 to Upper Shell Weld
- Unit 1 Inlet Nozzle 1 to Upper Shell Weld
- Unit 1 Inlet Nozzle 3 to Upper Shell Weld
- Unit 2 Outlet Nozzle 1 to Upper Shell Weld
- Unit 2 Inlet Nozzle 1 to Upper Shell Weld
- Unit 2 Inlet Nozzle 3 to Upper Shell Weld

For Unit 1, the limiting USE value for materials not requiring an EMA at 68 EFPY is 54 ft-lb (see Table 4.2.2-5); this value corresponds to the Inlet Nozzle to Upper Shell Welds (Heat # 299L44) using Position 2.2. For Unit 2, the limiting USE value for materials not requiring an EMA at 68 EFPY is also 54 ft-lb (see Table 4.2.2-6); this value corresponds to the Outlet Nozzle to Upper Shell Welds (Rotterdam) using Position 1.2. Except for the materials listed above, all of the beltline and extended beltline materials in the Units 1 and 2 RVs are projected to remain above the USE screening criterion value of 50 ft-lb (per 10 CFR 50, Appendix G) through the subsequent period of extended operation (68 EFPY).

Equivalent Margins Analysis

The ASME Code, Section XI, acceptance criteria for Levels A through D Service Loadings for all Units 1 and 2 RV beltline and extended beltline Linde 80 welds are satisfied and are reported in Framatome Reports BAW-2192, Supplement 1P-A (Revision 0), "Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W Owners Reactor Vessel Working Group for Levels A & B Service Loads Topical Report," (Reference 4.8-23) and BAW-2178, Supplement 1P-A (Revision 0), "Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W Owners Reactor Vessel Working Group for Levels C & D Service Loads Topical Report," (Reference 4.8-24) ~~submitted to the NRC in December 2017~~. The Surry Power Plant specific versions of the EMA are documented in following reports:

- ANP-3679P, Revision 0, "Low Upper-Shelf Toughness Fracture Mechanics Analysis for Surry Units 1 and 2 Reactor Vessels for Levels A & B Service Loads at 80-Years" (Reference 4.8-25)
- ANP-3679NP, Revision 0, "Low Upper-Shelf Toughness Fracture Mechanics Analysis for Surry Units 1 and 2 Reactor Vessels for Levels A & B Service Loads at 80-Years"
- ANP-3680P, Revision 0, "Low Upper-Shelf Toughness Fracture Mechanics Analysis for Surry Units 1 and 2 Reactor Vessels for Levels C & D Service Loads at 80-Years" (Reference 4.8-26)
- ANP-3680NP, Revision 0, "Low Upper-Shelf Toughness Fracture Mechanics Analysis for Surry Units 1 and 2 Reactor Vessels for Levels C & D Service Loads at 80-Years"

The plant-specific EMA reports contain the same information as in BAW-2192, Supplement 1P-A and BAW-2178, Supplement 1P-A except that the information for Oconee 1, 2, and 3 and Turkey Point 3 and 4 has been removed.

The 80-year clad/base metal fluence values reported in Table 3 -1 of BAW-2178, Supplement 1P-A, and Table 3-1 of BAW-2192, Supplement 1P-A have been confirmed to bound the 68 EFPY fluence values reported in Table 4.2.1-1 and Table 4.2.1-2. The EMAs conservatively utilized 80-year fluence values shown in (e) of at least an order of magnitude higher than the 68 EFPY nozzle fluence reported in Table 4.2.1-1 and Table 4.2.1-2. In addition, the weld chemistry data reported in Table 3-1 of BAW-2178, Supplement 1P-A, and Table 3-1 of BAW-2192, Supplement 1P-A is consistent with weld chemistry reported in Tables 4.2.2-1 through Table 4.2.2-4. The level C and D limiting design transients reported in Section 4.3.2 of BAW-2178P, Supplement 1P-A, are applicable to Units 1 and 2 and are based on a review of the ASME Code, Section III, Reactor Vessel Design Specification transients and the UFSAR Chapter 14 events relative to transients that would result in the highest thermal stresses coupled with pressure stresses relative to the EMA analysis; this satisfies Regulatory Guide 1.161 with respect to Level C and D transient selection. The materials of construction, RV geometry, and range of explanatory variables for the J-R model (Section A.5 of BAW-2192, Supplement 1P-A) reported in the topical reports are confirmed to be applicable to Linde 80 and Rotterdam beltline and extended beltline welds at Units 1 and 2.

As such, Units 1 and 2 are bounded by topical report submittals BAW-2178, Supplement 1P-A, and BAW-2192, Supplement 1P-A relative to fluence, weld chemistry, geometry, materials of construction, design transients and the J-R model applicability. The results of the EMA for Units 1 and 2, as reported in BAW-2178 P/NP and BAW-2192 P/NP, are summarized below.

Levels A & B Service Loadings

Reactor Vessel Shell Welds (Beltline)

The limiting RV shell weld is Unit 1 axial weld SA-1526.

- With factors of safety of 1.15 on pressure and 1.0 on thermal loading, the applied J-integral (J1) is less than the J-integral of the material at a ductile flaw extension of 0.10 in. (J0.1). The ratio J0.1/J1 is greater than the required value of 1.0.
- With a factor of safety of 1.25 on pressure and 1.0 on thermal loading, flaw extensions are ductile and stable since the slope of the applied J-integral curve is less than the slope of the lower bound J-R curve at the point where the two curves intersect.

Reactor Vessel Transition Welds and RV Nozzle Welds (Extended Beltline)

- The limiting weld for Units 1 and 2 considering RV transition welds (upper and lower) and the RV inlet and outlet nozzle-to-shell welds is the longitudinal weld SA-1585 near the base of the transition section.
- With factors of safety of 1.15 on pressure and 1.0 on thermal loading, the applied J-integral (J1) is less than the J-integral of the material at a ductile flaw extension of 0.10 in. (J0.1). The ratio J0.1/J1 is greater than the required value of 1.0.
- With a factor of safety of 1.25 on pressure and 1.0 on thermal loading, flaw extensions are ductile and stable since the slope of the applied J-integral curve is less than the slope of the lower bound J-R curve at the point where the two curves intersect.

<u>Levels C & D Service Loadings</u>

Reactor Vessel Shell Welds (Beltline)

The limiting weld among the RV shell welds is Unit 1 longitudinal weld SA-1526. The limiting transient for Level C & D service Loads is the SSDC 1.3 steam line break.

- With a factor of safety of 1.0 on loading, the applied J-integral (J1) for the limiting RV shell weld (Unit 1, SA-1526) is less than the lower bound J-integral of the material at a ductile flaw extension of 0.10 inch (J0.1) with a ratio J0.1/J1 that is greater than the required value of 1.0.
- With a factor of safety of 1.0 on loading, flaw extensions are ductile and stable for the limiting RV shell weld (SA-1526) since the slope of the applied J-integral curve is less than the slopes of both the lower bound and mean J-R curves at the points of intersection.
- For weld SA-1526 it was demonstrated that flaw growth is stable at much less than 75% of the vessel wall thickness. It has also been shown that the remaining ligament is sufficient to preclude tensile instability.

Reactor Vessel Transition Welds and RV Nozzle Welds (Extended Beltline)

The upper transition weld and RV inlet and outlet nozzle-to-shell welds were evaluated for Levels C and D Service Loadings. The limiting transient for Level C & D service loads is the SSDC 1.3 steam line break.

- With a factor of safety of 1.0 on loading, the applied J-integral (J1) for the RV nozzle-to-shell welds and upper transition weld are less than the lower bound J-integral of the material at a ductile flaw extension of 0.10 inch (J0.1). All ratios are greater than 1.0.
- With a factor of safety of 1.0 on loading, flaw extensions are ductile and stable for the limiting RV outlet nozzle-to-shell weld (i.e., limiting location considering RV nozzle-to-shell welds and upper transition weld).
- For the RV outlet nozzle-to-shell weld it was demonstrated that flaw growth is stable at much less than 75% of the vessel wall thickness. Tensile instability was not explicitly calculated but because this section of the RV is thicker compared to the RV shell welds, it is considered to be bounded by the RV shell location.

B&WOG J-R Model

The original B&WOG J-R Model 4B reported in BAW-2192PA, Supplement 1, Appendix A, was used to obtain J material (i.e., J(0.1)) for the 80-year equivalent margins analyses reported in BAW-2192, Supplement 1P-A, and BAW-2178, Supplement 1P-A. Model 4B is based on fracture toughness data (1352 J delta-a data points) irradiated to a fluence ranging from 0.0 to 8.45×10^{18} n/cm^2, which is less than the peak 1/10T 80-year fluence projected for Units 1 and 2. To further substantiate the use of the B&WOG J-R model, the original J delta-a data used to generate the B&WOG J-R model 4B was used to independently benchmark the original B&WOG model using the R-project statistical tool. The benchmark is designated B&WOG J-R Model 5B. New J-R data (419 new J delta-a data points with fluence to 5.8×10^{19} n/cm^2) were then added to the original population of welds (total population of 1774 data points) and the fitting coefficients (assuming the same model form) were generated. The B&WOG model that includes the total population of J delta-a data (1774) is designated Model 6B. Model 6B is based on test data out to a fluence of 5.8×10^{19} n/cm^2, which is greater than the peak 1/4T fluence of 8.16×10^{18} n/cm^2 and 1/10T fluence of 1.083×10^{19} n/cm^2 for Units 1 and 2 limiting weld SA-1526.

Use of Model 6B for fluence values in excess of 5.8×10^{19} n/cm^2 is considered to be a model extrapolation and the uncertainty may increase (i.e., -2SE). Fluence estimates at T/4 and T/10 are well below 5.8×10^{19} n/cm^2 and the J-R Model is used well within the interpolation range (i.e., for weld SA-1526 fluence equals 8.16×10^{18} n/cm^2 at 1/4T and 1.083×10^{19} n/cm^2 at T/10). For Units 1 and 2, use of Model 6B (model extrapolation) increased the J(0.1)/J1 by approximately 6% for Level A and B, and 5% for Level C and D when compared to Model 4B, and, all margins remain above the acceptance criterion of 1.0. In addition, the combination of Level C and D acceptance criteria applied to Level D transients provides additional conservatism in the equivalent margins analyses. The B&WOG J-R models (including Models 4B and 6B) are discussed in BAW-2192, Supplement 1P-A, Appendix A.

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

The USE analyses have been projected to the end of the subsequent period of extended operation.

4.8-16 Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," May 1988.

4.8-17 BAW-2324, "Analysis of Capsule X Virginia Power Surry Unit No. 1, Reactor Vessel Material Surveillance Program," April 1998.

4.8-18 WCAP-16001, Revision 0, "Analysis of Capsule Y from Dominion Surry Unit 2 Reactor Vessel Radiation Surveillance Program," February 2003.

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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, 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.~~e.g., ultrasonic testing, ~~and~~ eddy current testing and acoustic impact tap examination), 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

A1.24 FLUX THIMBLE TUBE INSPECTION

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

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

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

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

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

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

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

A1.26 LUBRICATING OIL ANALYSIS

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

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
7	*PWR Vessel Internals* program	The *PWR Vessel Internals* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised for each reload to summarize the average power density, the heat generation figure-of-merit, and the dimensional parameter for the distance between the active fuel and the upper core plate. 2. Procedures will be revised to require the visual inspection (EVT-1) of the control rod guide tube (CRGT) lower flange weld to require that the inspection include 100% of the outer CRGT lower flange weld surfaces and 0.25-inch of the adjacent base metal. 3. Procedures will be revised to require the visual inspection (VT-3) of the accessible surfaces for the control rod guide tube support pins and support pin nuts for Unit 1 only (plant-specific component). 4. Procedures will be revised to require the addition of a note indicating that a bolting inspection can be credited only if at least 75% of the total bolt population is examined. 5. Procedures will be revised to require visual inspection (VT-3) for 100% of the baffle-edge bolts that are accessible from the core side. 6. Procedures will be revised to require volumetric (UT) examinations for 100% of accessible baffle-former bolts (including corner bolts) at least every 10 years. MRP-2017-009 states that baseline volumetric (UT) examinations shall be performed no later than 30 EFPY for NSAL 16-1 Tier 2 plants, including the Surry units. The guidance further states that initial baseline UT exams performed prior to 1/1/2018 are acceptable. Examinations were performed in 2010 for Unit 1 and in 2011 for Unit 2. For the Surry units with the down-flow configuration that have <3% indications and no clustering, subsequent UT examinations are performed on a 10-year interval. 7. Procedures will be revised to address expansion criteria when degradation occurs for clusters of baffle-former bolts. 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.(Revised - First Annual Amendment) 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 visual (VT-3) inspection 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 (MRP 2018-002, Item 3.b) 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. 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.	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.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
7	*PWR Vessel Internals* program	8. Procedures will be revised to require visual examinations (EVT-1) for 100% of one side (ID or OD) of the circumference for the core barrel upper flange weld, and ¾" of adjacent base metal (minimum 50% examination coverage) (Primary component) 9. ~~Procedures will be revised to require visual examinations (EVT-1) for 100% of the OD surface of the core barrel lower flange weld and ¾" adjacent base metal (minimum 50% examination coverage)~~Procedures will be revised to require visual examinations (EVT-1) for 100% of the OD surface of the core barrel lower flange weld and ¾" adjacent base metal (minimum 75% examination coverage unless access limitations prevent examination of more than 50% of the weld). (Expansion component) (Revised - First Annual Amendment) 10. Procedures will be revised to perform inspections of control rod guide tube (CRGT) thermal sleeves as indicated in MRP 2018-027. MRP 2018-027 refers to the Westinghouse NSAL 18-1 recommendation that, based on operating experience (OE) from international PWR plants related to wear of reactor vessel closure head control rod drive mechanism (CRDM) thermal sleeve flanges resulting in control rod stoppage during plant restart operations, a visual inspection should be performed during the next refueling outage after issuance of the NSAL, and during each subsequent refueling outage, for the tops of the CRGTs to determine whether any thermal sleeves have lowered significantly or are in a failed state. For the Surry plants, the guidance is to look for shiny marks on the top edge of the upper guide tube enclosure. Also, during the next under-head inspection, the guidance is to perform a visual inspection of the bottom of the thermal sleeve guide funnels to look for any shiny surfaces on the bottom surface of the guide funnel that would indicate that the thermal sleeve guide funnels have dropped to a point where they are in contact with the top of the guide tube. A visual inspection of thermal sleeve guide funnel elevations is recommended to identify whether any sleeves are noticeably lower than others (Primary component). 11. Procedures will be revised to require visual examinations (VT-3) for the following: a. Top and bottom edges of baffle plates to identify misalignment (Primary component). b. General condition of the baffle plates to identify warping or void swelling (Primary component). c. Surfaces of the upper internals fuel alignment pins to identify wear of the malcomized surface (Existing Programs component). d. Surfaces of the lower internals fuel alignment pins to identify wear of the malcomized surface (Existing Programs component). e. Clevis insert bolts and clevis insert dowels (Primary component).	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.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
7	*PWR Vessel Internals* program	12. Procedures will be revised for contingency tasks to require inspection of the following expansion components if necessitated by relevant indications being found for associated primary components: a. Remaining control rod guide tube lower flange welds not inspected as Primary component (EVT-1) b. Control rod guide tube (CRGT) continuous section sheaths and C-tubes in accordance with the requirements of WCAP-17451-P, Revision 2. (Added - First Annual Amendment) c. Bottom-mounted instrumentation column bodies (100% of BMI column bodies for which difficulty is detected during flux thimble insertion / withdrawal; VT-3) d. Lower support column bodies (25% of column bodies as visible from above the core plate; VT-3) e. Barrel-former bolts (100% of accessible bolts, minimum of 75% of the total population; UT) f. Lower support column bolts (100% of accessible bolts, minimum of 75% of the total population; UT) 13. Procedures will be revised to require that the inspections for the radial support keys and clevis inserts are to include the Stellite wear surfaces (Primary component, MRP 2018-022). 14. Procedures will be revised to require visual inspections (VT-3) of the guide cards in at least 37 of the 48 control rod guide tubes, and will include associated acceptance criteria. Guidance from WCAP-17451-P, "Reactor Internals Guide Tube Wear – Westinghouse Domestic Fleet Operational Projections," and MRP 2018-07, "Transmittal of NEI 03-08 Needed Guidance to Address Accelerated Guide Card Wear Operating Experience (OE) Discussed in NSAL-17-1," will be included for the inspection of control rod guide cards.	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.

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: (Revised - First Annual Amendment) a. Core barrel upper, middle, and lower axial welds (100% of weld length and 3/4" of adjacent base metal - minimum 75% examination coverage unless access limitations prevent examination of more than 50% of the weld ~~– 50% examination coverage~~; EVT-1) • A one-time enhanced visual (EVT-1) examination of the core barrel middle axial weld (MAW) and lower axial weld (LAW) will be performed during the sixth inservice inspection interval (i.e., a "50-year inspection") no later than six months prior to the subsequent period of extended operation. The examination will include coverage for 100% of the accessible weld lengths from the core barrel OD and ¾" of base metal on each side the weld AND a vertical zone on each side of the inaccessible portion of the barrel containing the known location of the axial weld. Each vertical zone shall be a minimum of 3/4" wide and cover the full distance parallel to the inaccessible height of the weld. b. Core barrel upper girth weld (100% of weld length ~~– 50% examination coverage~~and ¾" of adjacent base metal – minimum 75% examination coverage unless access limitations prevent examination of more than 50% of the weld; EVT-1) c. ~~Core barrel lower flange weld (100% of weld length – 50% examination coverage; EVT-1)~~ d. Lower support forging (25% of bottom (non-core side) surface; VT-3) e. Upper core plate (25% of ~~accessible~~core-side 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.

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 require two soil corrosivity samples be performed: one adjacent to the Unit 1 circulating water inlet piping and another adjacent to the Unit 2 circulating water inlet piping. Sampling will be performed on a 10 year interval. Data collected at each location will include: soil resistivity, soil consortia (bacteria), pH, moisture, chlorides, sulfates, and redox potential. In addition to evaluating each individual parameter, corrosivity of carbon steel reinforcement and concrete degradation in high sulfate and acidic environments will be evaluated. (Added - Set 3 RAIs) 7. 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) 8. 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. 9. 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. Examination procedures and personnel who perform acoustic examinations of CFRP lined piping will be qualified consistent with mandatory Appendix VI and section 5400 of ASME Code Case N-871. (Added - Set 2 RAIs) (Revised - Change Notice 4) 10. 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~~three 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) (Revised - Change Notice 4)	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 require accessible surfaces of the CFRP linings at each terminal end to be acoustically impact tap examined in accordance with Mandatory Appendix V, "Inservice Examination", Section V-2500, ASME Code Case N-871 section 5250(a) and ~~5250(c)~~ Section 5350. The acoustic examination of terminal ends will be capable of detecting and sizing delaminations and voids in any composite or bonding layer with dimensions equal to or less than those permitted by Section 4390(b)(3). The acoustic impact tap examination procedure sections will also be enhanced to add Section 5111 (d), that provides consideration of the impact of in-situ ambient noise levels on application of the procedure and qualification of procedures and personnel. The qualification testing will be conducted in an area where the ambient noise level is equal to or higher than the noise level where the in-situ testing will be performed. 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) (Added - Set 2 RAIs) (Revised - Change Notice 4) 12. 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) (Revised - Change Notice 4) 13. 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. 14. 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. 15. 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) 16. Procedures will be revised to include verification that predicted wall thicknesses at the next scheduled inspection will be greater than the minimum wall thicknesses. 17. Procedures will be revised to include criteria for the extent and rate of on-going degradation that will prompt additional corrective actions. 18. Procedures will be revised to identify acceptance criteria for visual inspection of concrete piping and components such as the absence of cracking and loss of material, provided that minor cracking and loss of material in concrete may be acceptable where there is no evidence of leakage, exposed rebar or reinforcing "hoop" bands or rust staining from such reinforcing elements.	B2.1.11	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
11	*Open-Cycle Cooling Water* program	19. 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) 20. 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. 21. 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. 22. 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
27	*Buried and Underground Piping and Tanks* program	The *Buried and Underground Piping and Tanks* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to establish an upper limit of -1200mV for pipe-to-soil potential measurements of coated pipes so as to preclude potential damage to coatings. 2. ~~Procedures will be revised to include visual inspection requirements and acceptance criteria for:~~(Completed - Change Notice 2) a. ~~Absence of cracking in fiberglass reinforced plastic components and evaluation of blisters, gouges, or wear~~ b. ~~Minor cracking and loss of material in concrete or cementitious material provided there is no evidence of leakage exposed or rust staining from rebar or reinforcing "hoop" bands~~ 3. Procedures will be revised to obtain pipe-to-soil potential measurements for piping in the scope of SLR during the next soil survey within 10 years prior to entering the subsequent period of operation. (Added - Set 1 RAIs) 4. Procedures will be revised to require uncoated buried stainless steel tubing segments in the fuel oil system be inspected prior to the subsequent period of extended operation. After inspection, each uncoated stainless steel segment will be coated consistent with Table 1 of NACE SP0169-2007, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems."~~"Standard Recommended Practice, Cathodic Protection of Prestressed Concrete Cylinder Pipelines."~~ (Added - Set 1 RAIs) (Revised - Set 3 RAIs) 5. A cathodic protection system will be installed for protection of the 24-inch service water piping at the Low Level Intake Structure five years before entering the subsequent period of operation. (Added - Set 3 RAIs) 6. A cathodic protection system will be installed for protection of each unit's buried carbon steel condensate system and auxiliary feedwater system piping from the emergency condensate storage tank and the emergency condensate makeup tank to the service building five years before entering the subsequent period of operation. (Added - Change Notice 4) 7. Procedure(s) will be developed to perform a one-time inspection (one excavation) for evidence of concrete aging (below grade) associated with either the Unit 1 or Unit 2 High Level Intake Structures, or the south side of the Turbine Building, or the Fire Water Pump House. For the selected structure, a minimum 50 ft^2 concrete surface area below the frost line will be inspected by the one-time inspection. The procedure will require that, as a surrogate location, the evaluation of the one-time inspection results also include evaluation of the acceptability of the eight inaccessible 96-inch CW pipes located between the High Level Intake Structures and the Turbine Building using the guidance in ACI 349-3R. (Added - Change Notice 4) 8. Procedures will be revised to specify that cathodic protection surveys use the -850mV polarized potential, ~~-~~instant off criterion specified in NACE SP0169-2007 for steel piping acceptance criteria unless a suitable alternative polarization criteria can be demonstrated. Alternatives include the -100mV polarization criteria, -750mV criterion (soil resistivity is less than 100,000 ohm-cm), -650mV criterion (soil resistivity is greater than 100,000 ohm-cm), or verification of less than 1 mpy loss of material rate. ~~Alternatives will be demonstrated to be effective through use of buried coupons, electrical resistance probes, or placement of reference cells in the immediate vicinity of the piping being measured.~~	B2.1.27	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
27	*Buried and Underground Piping and Tanks* program	The external loss of material rate is verified: • Every year when verifying the effectiveness of the cathodic protection system by measuring the loss of material rate. • Every 2 years when using the 100 mV minimum polarization. • Every 5 years when using the -750 or -650 criteria associated with higher resistivity soils. The soil resistivity is verified every 5 years. As an alternative to verifying the effectiveness of the cathodic protection system every five years, soil resistivity testing is conducted annually during a period of time when the soil resistivity would be expected to be at its lowest value (e.g., maximum rainfall periods). Upon completion of ten annual consecutive soil samples, soil resistivity testing can be extended to every five years if the results of the soil sample tests consistently have verified that the resistivity did not fall outside of the range being credited (e.g., for the -750 mV relative to a CSE, instant off criterion, measured soil resistivity values were greater than 10,000 ohm-cm). When using the electrical resistance corrosion rate probes: a. The individual determining the installation of the probes and method of use will be qualified to NACE CP4, "Cathodic Protection Specialist" or similar b. The impact of significant site features and local soil conditions will be factored into placement of the probes and use of the data (Revised - Change Notice 2 and Set 1 RAIs)	B2.1.27	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

B2.1.7 PWR Vessel Internals

Program Description

The *PWR Vessel Internals* program is an existing condition monitoring program that manages cracking, loss of material, loss of fracture toughness, change in dimensions due to void swelling, and loss of preload for the reactor vessel internals (RVI). The aging effect of cracking includes stress corrosion cracking (SCC), primary water stress corrosion cracking (PWSCC), irradiation-assisted stress corrosion (IASCC), and cracking due to fatigue/cyclic loading. Degradation due to loss of material can be induced by wear, and loss of fracture toughness is the result of thermal aging and neutron irradiation embrittlement. Potential causes for the aging effect of changes in dimensions are void swelling or distortion, and loss of preload can result from thermal and irradiation-enhanced stress relaxation or creep.

The *PWR Vessel Internals* program relies on implementation of the inspection and evaluation guidelines in Electric Power Research Institute (EPRI) Technical Report 1022863, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A)," and EPRI Technical Report 1016609, "Materials Reliability Program: Inspection Standard for Pressurized Water Reactor Internals (MRP-228)," to manage the aging effects on the reactor vessel internal components, as supplemented by a gap analysis. The gap analysis includes integration of EPRI Technical Report 3002005349, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines," (MRP-227, Revision 1), which is implemented in accordance with Nuclear Energy Institute (NEI) 03-08, "Guideline for the Management of Materials Issues". MRP-227, Revision 1, includes one "mandatory" and four "needed" NEI 03-08 implementation requirements for the *PWR Vessel Internals* program. The guidelines listed in MRP-227, Revision 1, provide an appropriate aging management methodology for the RVI components. The gap analysis also integrates the interim guidance from MRP 2018-022, "Transmittal of MRP-191 Screening, Ranking, and Categorization Results and Interim Guidance in Support of Subsequent License Renewal at U.S. PWR Plants". The inspections of the RVI components are implemented in accordance with EPRI Report 3002005386, "Materials Reliability Program: Inspection Standard for Pressurized Water Reactor Internals – 2015 Update (MRP-228, Rev. 2)".

The Safety Evaluation Report that the NRC issued for the approved version (i.e., MRP-227-A) of MRP-227, Revision 0, dated December 16, 2011, included eight Applicant/Licensee Action Items (A/LAI) that required resolution. Six of those items are applicable for Westinghouse reactors. The six items that require resolution for SPS have been addressed such that no open items exist for the *PWR Vessel Internals* program in preparation for the subsequent period of extended operation.

The *PWR Vessel Internals* program applies the guidance in MRP-227, Revision 1 for inspecting, evaluating, and, if applicable, dispositioning non-conforming RVI components at Units 1 and 2. The selection of RVI components to be inspected is based on a four-step ranking process that includes the designations of "primary," "expansion," "existing programs" (such as American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section XI, Examination Category B-N-3, examinations of core support structures), and "no additional measures." The program includes expanding examinations (i.e., "expansion" components) if the observed extent of degradation for the "primary" components exceeds acceptance criteria.

The following listing identifies the changes that are included in the PWR Vessel Internals program based on MRP 2018-022:

- The corner bolts (Baffle-former Assembly) were added to the population of baffle-former bolts for Primary component.
- Clevis insert bolts (Alignment and Interfacing Components) were elevated from Existing Programs component to Primary component. The scope of this item was expanded to include the clevis insert dowels.
- Thermal sleeves (Alignment and Interfacing Components) were added as a Primary component.
- Radial support keys Stellite wear surface (Radial Support Keys) was added as a Primary component.
- Clevis bearing Stellite wear surface (Alignment and Interfacing Components) was added as a Primary component.
- Fuel alignment pins (Malcomized) (Upper Internals Assembly) were added as an Existing programs component.
- Fuel alignment pins (Malcomized) (Lower Internals Assembly) were added as an Existing programs component.

The initial phase of inspections for RVI inspections began in 2010 for Unit 1 and in 2011 for Unit 2. In 2013 for Unit 1 and in 2014 for Unit 2, RVI inspections were completed for the 'primary' components identified for the initial license renewal period. The inspections included the following components:

- Control rod guide tube assembly guide cards
- Control rod guide tube assembly lower flange welds
- Core barrel assembly upper flange weld
- Core barrel assembly lower girth weld
- Baffle-former assembly baffle-edge bolts
- Baffle-former assembly baffle-former bolts
- Baffle-former assembly baffle plates, and indirect effects of void swelling
- Alignment and interfacing components internals hold down spring
- Clevis insert bolting
- Thermal shield flexures

NUREG-2191 Consistency

The *PWR Vessel Internals* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M16A, PWR Vessel Internals.

Exception Summary

None

Enhancements

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

Parameters Monitored or Inspected (Element 3)

1. Procedures will be revised for each reload to summarize the average power density, the heat generation figure-of-merit, and the dimensional parameter for the distance between the active fuel and the upper core plate.

Detection of Aging Effects (Element 4)

2. Procedures will be revised to require the visual inspection (EVT-1) of the control rod guide tube (CRGT) lower flange weld to require that the inspection include 100% of the outer CRGT lower flange weld surfaces and 0.25-inch of the adjacent base metal.
3. Procedures will be revised to require the visual inspection (VT-3) of the accessible surfaces for the control rod guide tube support pins and support pin nuts for Unit 1 only (plant-specific component).

4. Procedures will be revised to require the addition of a note indicating that a bolting inspection can be credited only if at least 75% of the total bolt population is examined.

5. Procedures will be revised to require visual inspection (VT-3) for 100% of the baffle-edge bolts that are accessible from the core side.

6. Procedures will be revised to require volumetric (UT) examinations for 100% of accessible baffle-former bolts (including corner bolts) at least every 10 years. MRP-2017-009 states that baseline volumetric (UT) examinations shall be performed no later than 30 EFPY for NSAL 16-1 Tier 2 plants, including the Surry units. The guidance further states that initial baseline UT exams performed prior to 1/1/2018 are acceptable. Examinations were performed in 2010 for Unit 1 and in 2011 for Unit 2. For the Surry units with the down-flow configuration that have <3% indications and no clustering, subsequent UT examinations are performed on a 10-year interval.

7. Procedures will be revised to address expansion criteria when degradation occurs for clusters of baffle-former bolts. 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. (Revised - First Annual Amendment)

   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 visual (VT-3) inspection 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 (MRP 2018-002, Item 3.b) 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.

   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.

8. Procedures will be revised to require visual examinations (EVT-1) for 100% of one side (ID or OD) of the circumference for the core barrel upper flange weld, and 0.75-inch of adjacent base metal (minimum 50% examination coverage) (Primary component)

9. ~~Procedures will be revised to require visual examinations (EVT-1) for 100% of the OD surface of the core barrel lower flange weld and 0.75-inch adjacent base metal (minimum 50% examination coverage)~~Procedures will be revised to require visual examinations (EVT-1) for 100% of the OD surface of the core barrel lower flange weld and ¾" adjacent base metal (minimum 75% examination coverage unless access limitations prevent examination of more than 50% of the weld). (Expansion component) (Revised - First Annual Amendment)

10. Procedures will be revised to perform inspections of control rod guide tube (CRGT) thermal sleeves as indicated in MRP 2018-027. MRP 2018-027 refers to the Westinghouse NSAL 18-1 recommendation that, based on operating experience (OE) from international PWR plants related to wear of reactor vessel closure head control rod drive mechanism (CRDM) thermal sleeve flanges resulting in control rod stoppage during plant restart operations, a visual inspection should be performed during the next refueling outage after issuance of the NSAL, and during each subsequent refueling outage, for the tops of the CRGTs to determine whether any thermal sleeves have lowered significantly or are in a failed state. For the Surry plants, the guidance is to look for shiny marks on the top edge of the upper guide tube enclosure. Also, during the next under-head inspection, the guidance is to perform a visual inspection of the bottom of the thermal sleeve guide funnels to look for any shiny surfaces on the bottom surface of the guide funnel that would indicate that the thermal sleeve guide funnels have dropped to a point where they are in contact with the top of the guide tube. A visual inspection of thermal sleeve guide funnel elevations is recommended to identify whether any sleeves are noticeably lower than others (Primary component).

11. Procedures will be revised to require visual examinations (VT-3) for the following:
    a. Top and bottom edges of baffle plates to identify misalignment (Primary component).
    b. General condition of the baffle plates to identify warping or void swelling (Primary component).
    c. Surfaces of the upper internals fuel alignment pins to identify wear of the malcomized surface (Existing Programs component).
    d. Surfaces of the lower internals fuel alignment pins to identify wear of the malcomized surface (Existing Programs component).
    e. Clevis insert bolts and clevis insert dowels (Primary component).

12. Procedures will be revised for contingency tasks to require inspection of the following expansion components if necessitated by relevant indications being found for associated primary components:

a. Remaining control rod guide tube lower flange welds not inspected as Primary component (EVT-1)

b. Control rod guide tube (CRGT) continuous section sheaths and C-tubes in accordance with the requirements of WCAP-17451-P, Revision 2. (Added - First Annual Amendment)

c. Bottom-mounted instrumentation column bodies (100% of BMI column bodies for which difficulty is detected during flux thimble insertion / withdrawal; VT-3)

d. Lower support column bodies (25% of column bodies as visible from above the core plate; VT-3)

e. Barrel-former bolts (100% of accessible bolts, minimum of 75% of the total population; UT)

f. Lower support column bolts (100% of accessible bolts, minimum of 75% of the total population; UT)

13. Procedures will be revised to require that the inspections for the radial support keys and clevis inserts are to include the Stellite wear surfaces (Primary component, MRP 2018-022).

14. Procedures will be revised to require visual inspections (VT-3) of the guide cards in at least 37 of the 48 control rod guide tubes, and will include associated acceptance criteria. Guidance from WCAP-17451-P, "Reactor Internals Guide Tube Wear – Westinghouse Domestic Fleet Operational Projections," and MRP 2018-07, "Transmittal of NEI 03-08 Needed Guidance to Address Accelerated Guide Card Wear Operating Experience (OE) Discussed in NSAL-17-1," will be included for the inspection of control rod guide cards.

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: (Revised - First Annual Amendment)

a. Core barrel upper, middle, and lower axial welds (100% of weld length ~~– 50% examination coverage~~and ¾" of adjacent base metal – minimum 75% examination coverage unless access limitations prevent examination of more than 50% of the weld; EVT-1)

- A one-time enhanced visual (EVT-1) examination of the core barrel middle axial weld (MAW) and lower axial weld (LAW) will be performed during the sixth inservice inspection interval (i.e., a "50-year inspection") no later than six months prior to the subsequent period of extended operation. The examination will include coverage for 100% of the accessible weld lengths from the core barrel OD and ¾" of base metal on each side the weld AND a vertical zone on each side of the inaccessible portion of the barrel containing the known location of the axial weld. Each vertical zone shall be a minimum of 3/4" wide and cover the full distance parallel to the inaccessible height of the weld.

b. Core barrel upper girth weld (100% of weld length ~~– 50% examination coverage~~and ¾" of adjacent base metal – minimum 75% examination coverage unless access limitations prevent examination of more than 50% of the weld; EVT-1)

c. ~~Core barrel lower flange weld (100% of weld length – 50% examination coverage; EVT-1)~~

d. Lower support forging (25% of bottom (non-core side) surface; VT-3)

e. Upper core plate (25% of ~~accessible~~ core side surfaces; VT-3)

Monitoring and Trending (Element 5)

17. A procedure for visual examinations will be revised to identify the examiner qualifications which are applicable for EVT-1 examinations.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *PWR Vessel Internals* 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 November 2010, VT-3 and UT examinations of baffle-former bolts were performed for Unit 1. The entire population of 1088 bolts was inspected. There were four findings. There were two bolts that were non-inspectable using UT due to deformation at the points on the hex heads that affected the back wall signal. However, reviews of the UT signals concluded there were no flaws and the VT-3 results showed no degradation. In general, the VT-3 examination results were satisfactory. One bolt had unacceptable VT-3 results due to a missing locking bar weld on one end, but that was evaluated to be an original fabrication condition, and no further action was recommended. The UT result for that bolt was satisfactory. One bolt was rejectable for UT results due to a flaw in the head-to-shank region, but had an acceptable VT-3 result.

   Baffle-edge bolt VT-3 examinations also were performed in 2010 for Unit 1. 936 accessible edge bolts were inspected. The only degradation that was noted for baffle-edge bolts was a missing weld on one end of the locking bar on one bolt which was determined to be an original fabrication condition. No further action was recommended.

2. In May 2011, VT-3 and UT examinations of baffle-former bolts were performed for Unit 2. The entire population of 1088 bolts was inspected. The VT-3 examination results were acceptable,

but there were two reportable indications from the UT examinations. The visual examination for those two non-adjacent bolts showed no structural damage to the bolt head, locking bar or locking bar welds. The two indications were bounded by existing analysis which confirmed structural integrity and safety function of the reactor internals assembly. Baffle-edge bolt VT-3 examinations also were performed in 2011 for Unit 2. 936 accessible edge bolts were inspected. No degradation of baffle edge bolts was noted.

3. During refueling outages in 2012, control rod guide tubes (CRGT) assembly guide card inspections were performed for Units 1 and 2. The CRGTs had been replaced in Unit 1 in the mid-1980s; the CRGTs in Unit 2 were the original components. The inspection results in 2012 confirmed acceptable results for guide card wear. The nominal guide card slot width for 15x15 fuel is 0.277-inch. The maximum measured value for the slot width for Unit 1 was 0.2851-inch: for Unit 2, the value was 0.2850-inch. The nominal value for the second monitored parameter of ligament length is 0.1859-inch. The minimum measured value of ligament length was 0.165-inch. These differences of no more than 11% indicate no concern for guide card wear.

4. In May 2014, an examination of the Unit 2 radial support keyway at 270 degrees identified an area of material deformation. By visual estimation, the groove-like indication reduced the surface area by less than 5%. Due to no indication of current wear, it was concluded that minimal wear had occurred over an extended period of operation. An engineering evaluation determined that this slight reduction in surface area was insignificant and acceptable.

5. In May 2014, three relevant indications were noted on the reactor pressure vessel cladding. The first indication involved an impression of a fastener nut, and the second indication was the subject nut which was still in the vessel, but was subsequently removed. The third indication was an impact point where a component or part had come into contact with the cladding. The indication did not appear to contain any cracks or flaws that would have the possibility to grow. There was no distortion or displacement of the surrounding structure. The observed condition was evaluated to be acceptable without further action.

6. In September 2014, Westinghouse issued Technical Bulletin TB-14-5, "Reactor Internals Lower Radial Support Clevis Insert Cap Screw Degradation". The bulletin recommended that during the next 10-year reactor vessel exam when the core barrel is removed, a VT-1 should be performed on the clevis bolts. The Augmented Inspection Plan was revised to include the recommended NDE examination.

7. In August 2016, Westinghouse provided a summary of industry operating experience regarding baffle-former bolts. NSAL-16-1, "Baffle-former Bolts," designated SPS as a Tier 2b plant. For such plants, NSAL-16-1 recommended that records of previous UT inspections of bolting be reviewed to identify any indication for the onset of clustering in the bolt failure patterns. Clustering is defined as three or more adjacent bolts or a total number of failures in a single baffle plate greater than 40% of the total number of bolts on that baffle plate. Unit 1 has

a record of one UT bolting failure identified by UT examination, and Unit 2 has two. Therefore, a cluster failure concern (three or more adjacent failures) is not an issue for either unit.

8. In August 2016, Westinghouse issued Technical Bulletin TB-16-4, "Fuel Alignment Pin Malcomized Surface Degradation," after becoming aware of industry operating experience indicating degradation of lower core plate (LCP) and upper core plate (UCP) fuel alignment pins with a malcomized surface. As a result, those alignment pins have been added to the scope of inspections for the reactor vessel internals.

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

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

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

10. In November 2017, as part of oversight review activities, the Reactor Vessel Internals Inspection Activity (UFSAR Section 18.2.15) 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.

11. In April 2018, MRP letter 2018-010 recommended that plants currently in a refueling outage or scheduled for an outage visually examine the general condition of the top of the Control Rod Guide Tubes (CRGTs) for any shiny rings which is indicative of a thermal sleeve guide funnel having dropped to a point of being in contact. Operating experience at a non-U.S. Westinghouse-designed plant indicated thermal sleeve wear due to contact with the CRGT. A degraded thermal sleeve has been shown to interfere with the movement of the control rod. Additional information regarding this operating experience was provided in Westinghouse Nuclear Safety Advisory Letter NSAL-18-1, "Thermal Sleeve Flange Wear Leads to Stuck Control Rod," in July 2018. During the refueling outage for Unit 1 in Spring 2018, visual inspections were performed for the top of the CRGTs and for the bottom of the thermal sleeve funnels to look for shiny surfaces which indicate wear. No indications were found.

12. In January 2018, an AMA effectiveness review was performed of the Reactor Vessel Internals Inspection Activity (UFSAR Section 18.2.15). Information from the summary of that effectiveness review is provided below:

    The Reactor Vessel Internals Inspection Activity is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. The Reactor Vessel Internals Inspection Activity includes visual inspections and non-destructive examinations of components that comprise the reactor pressure vessel internals. Key elements of the activity that were reviewed included identification of reactor internals structural components to be inspected, inspection frequencies and techniques, evaluation and documentation of inspection results, repair/replacement tasks, industry initiatives, and program updates. The reviews were based on guidance from MRP-227-A per the requirements of NEI 03-08, and UFSAR Section 18.2.15 as well as license renewal commitment #14. Condition Reports (CRs) were reviewed for a 10-year period (July 2006-June 2016) to identify possible occurrences of age-related degradation for the reactor vessel internals.

    The initial examinations performed for the Reactor Vessel Internals Inspection Activity found degradation only for a few of the baffle-to-former bolts. Those findings were evaluated to not jeopardize the integrity of the reactor internals. There were no findings of degradation for other structural components in the reactor internals.

    Relevant industry documents that provide a basis for the Reactor Vessel Internals Inspection Activity include WCAP-17096, "Reactor Internals Acceptance Criteria Methodology and Data Requirements," WCAP-14577, "License Renewal Evaluation: Aging Management for Reactor Internals," WCAP-17451, "Reactor Internals Guide Tube Wear – Westinghouse Domestic Fleet Operational Projections," and NSAL-17-1,"Guide Tube Guide Card Wear Attributed to Ion Nitride Rod Cluster Control Assembly." The Fleet Lead for the Reactor Vessel Internals Inspection frequently participates in industry meetings and performs reviews of industry OE summaries to remain aware of potential needs to revise the scope, frequency, or techniques to be used for reactor internals examinations. There has been no need to make any such changes. Compliance with the guidance of MRP-227-A is maintained.

The above examples of operating experience provide objective evidence that the *PWR Vessel Internals* program includes activities to perform volumetric and visual inspections to identify cracking, loss of material, loss of fracture toughness, change in dimensions due to void swelling, and loss of preload for the reactor vessel internals within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *PWR Vessel Internals* 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 *PWR Vessel Internals* program, following enhancement, will effectively manage aging prior to loss of intended function.

Conclusion

The continued implementation of the *PWR Vessel Internals* 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, 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.

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 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)
7. Procedures will be enhanced to perform two soil corrosivity samples: one adjacent to the Unit 1 circulating water inlet piping and another adjacent to the Unit 2 circulating water inlet piping. Sampling will be performed on a 10 year interval. Data collected at each location will include: soil resistivity, soil consortia (bacteria), pH, moisture, chlorides, sulfates, and redox potential. In addition to evaluating each individual parameter, corrosivity of carbon steel reinforcement and concrete degradation in high sulfate and acidic environments will be evaluated. (Added - Set 3 RAIs)

Detection of Aging Effects (Element 4)

8. 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.
9. 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. Examination procedures and personnel ~~Personnel~~ who perform acoustic examinations of CFRP lined piping will be qualified consistent with mandatory Appendix VI and section 5400 of ASME Code Case N-871. (Added - Set 2 RAIs) (Revised - Change Notice 4)

10. 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~~three 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) (Revised - Change Notice 4)

11. 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 Mandatory Appendix V, "Inservice Examination", Section V-2500, ASME Code Case N-871 section 5250(a) and ~~5250(c)~~ Section 5350. The acoustic examination of terminal ends will be capable of detecting and sizing delaminations and voids in any composite or bonding layer with dimensions equal to or less than those permitted by Section 4390(b)(3). The acoustic impact tap examination procedure sections will also be enhanced to add Section 5111 (d), that provides consideration of the impact of in-situ ambient noise levels on application of the procedure and qualification of procedures and personnel. The qualification testing will be conducted in an area where the ambient noise level is equal to or higher than the noise level where the in-situ testing will be performed. 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) (Added - Set 2 RAIs) (Revised - Change Notice 4)

12. 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) (Revised - Change Notice 4)

Monitoring and Trending (Element 5)

13. 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.

14. 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.

15. 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)

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

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

18. 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.

19. 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)

20. 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.

21. 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.

22. 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 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. 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.

B2.1.16 Fire Water System

Program Description

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

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

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

The water-based fire protection system is normally maintained at required operating pressure and is monitored such that loss of system pressure is detected and corrective actions initiated. A low pressure condition is alarmed in the Main Control Room by the auto start of the electric motor driven fire pump, followed by the start of the diesel-driven fire pump if the low pressure condition continues to exist. The status of the fire pumps is indicated in the Main Control Room and at the fire pump control panels in the pump house. Both fire pumps may be manually started from the control room.

Piping wall thickness measurements are conducted when visual inspections detect surface irregularities indicative of unexpected levels of degradation. When the presence of organic or inorganic material sufficient to obstruct piping or sprinklers is detected, the material is removed and the source is detected and corrected.

Inspections and tests are performed by personnel qualified in accordance with procedures and programs to perform the specified task. Non-code inspections and tests follow procedures that include inspection parameters for items such as lighting, distance, offset, presence of protective coatings, and cleaning processes that ensure an adequate examination.

If a flow test (i.e., NFPA 25, 2011 Edition, Section 6.3.1) or a main drain test (i.e., NFPA 25, 2011 Edition, Section 13.2.5) does not meet the acceptance criteria due to current or projected degradation, additional tests are conducted. The number of increased tests is determined in accordance with the site's corrective action process; however, there are no fewer than two additional tests for each test that did not meet the acceptance criteria. The additional inspections are completed within the interval (i.e., five years or annual/refueling) in which the original test was conducted. If subsequent tests do not meet the acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of tests required. The additional tests will include at least one test at the other unit on site with the same material, environment, and aging effect combination.

In addition to piping replacement, actions will be taken to address instances of recurring corrosion due to microbiological induced corrosion. Low Frequency Electromagnetic Technique (LFET) or similar scanning technique will be used for screening 100 feet of accessible piping during each refueling cycle to detect changes in the wall thickness of the pipe. Thinned areas found during the LFET scan are followed up with pipe wall thickness examinations to ensure aging effects are managed and that wall thickness is within acceptable limits. In addition to the pipe wall thickness examination, opportunistic visual inspections of the fire protection system will be performed whenever the fire water system is opened for maintenance.

Aging of the external surfaces of buried and underground fire main piping is managed by the *Buried and Underground Piping and Tanks* program (B2.1.27). Loss of material and cracking of the internal surfaces of cement lined buried and underground fire main piping are managed by the *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28).

Aging of the fire water storage tank bottom surfaces exposed to oil soil are managed by the *Outdoor and Large Atmospheric Metallic Storage Tanks* program (B2.1.17).

When degraded coatings are detected during internal inspections of the fire water storage tanks, acceptance criteria, and corrective action recommendations of the *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) are followed. The training and qualification of individuals involved in coating/lining inspections of non-cementitious coatings/linings are conducted in accordance with ASTM International Standards endorsed in RG 1.54 including guidance from the staff associated with a particular standard.

NUREG-2191 Consistency

The *Fire Water System* program is an existing program that, following enhancement, will be ~~consistent, with exception, to NUREG-2191, Section XI.M27, Fire Water System.~~

Exception Summary

The following program element(s) are affected:

1. (Deleted exception for fire water storage tanks insulated external surface inspections - Change Notice 3) NUREG-2191, Table XI.M27-1, note 10 recommends main drain tests at each water-based system riser to determine if there is a change in the condition of the water piping and control valves on an annual or refueling outage interval. Surry Power Station will perform the main drain tests on twenty percent of the standpipes and risers every refueling cycle.

Justification for Exception

As indicated by NUREG-2191 Table XI.M27-1, note 10, access for some inspections is feasible only during refueling outages which are scheduled every eighteen months. Main drain tests on twenty percent of the standpipes and risers every eighteen months provide adequate information to determine the condition of the fire water piping is maintained consistent with the design basis.

Enhancements

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

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

1. (Sprinkler inspections - Completed Change Notice 1)
2. Prior to 50 years in service, sprinkler heads will be submitted for field-service testing by a recognized testing laboratory consistent with NFPA 25, 2011 Edition, Section 5.3.1. Additional representative samples will be field-service tested every 10 years thereafter to ensure signs of aging are detected in a timely manner.

   For wet pipe sprinkler systems, a one-time test of sprinklers that have been exposed to water including the sample size, sample selection criteria, and minimum time in service of tested sprinklers will be performed. At each unit, a sample of 3% or a maximum of ten sprinklers with no more than four sprinklers per structure shall be tested. Testing is based on a minimum time in service of fifty years and severity of operating conditions for each population. (Revised - Change Notice 2)
3. Procedures will be revised to specify:

a. Standpipe and system flow tests for hose stations at the hydraulically most limiting locations for each zone of the system on a five year interval to demonstrate the capability to provide the design pressure at required flow.

b. Acceptance criteria for wet pipe main drain tests. Flowing pressures from test to test will be monitored to determine if there is a 10% reduction in full flow pressure when compared to previously performed tests. The Corrective Action Program will determine the cause and necessary corrective action.

c. If a flow test or a main drain test does not meet acceptance criteria due to current or projected degradation additional tests are conducted. The number of increased tests is determined in accordance with the corrective action process; however, there are no fewer than two additional tests for each test that did not meet acceptance criteria. The additional inspections are completed within the interval in which the original test was conducted. If subsequent tests do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of tests. The additional tests include at least one test at the other unit with the same material, environment, and aging effect combination.

d. Main drains for the standpipes associated with hose stations within the scope of subsequent license renewal will also be added to main drain testing procedures.

4. Procedures will be revised to perform internal visual inspections of sprinkler and deluge system piping to identify internal corrosion, foreign material, and obstructions to flow. Follow-up volumetric examinations will be performed if internal visual inspections detect an unexpected level of degradation due to corrosion product deposition. If organic or foreign material, or internal flow blockage that could result in failure of system function is identified, then an obstruction investigation will be performed within the Corrective Action Program that includes removal of the material, an extent of condition determination, review for increased inspections, extent of follow-up examinations, and a flush in accordance with NFPA 25, 2011 Edition, Annex D.5, Flushing Procedures. The internal visual inspections will consist of the following: (Relocated from Enhancement 10 and Corrected - Change Notice 2)

   a. Wet pipe sprinkler systems - 50% of the wet pipe sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote sprinkler, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. During the next five-year inspection period, the alternate systems previously not inspected shall be inspected.

   b. Pre-action sprinkler systems - pre-action sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2.

c. Deluge systems - deluge systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2.

Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), and Monitoring and Trending (Element 5)

5. Procedures will be revised to perform system flow testing at flows representative of those expected during a fire. A flow resistance factor (C-factor) will be calculated to compare and trend the friction loss characteristics to the results from previous flow tests.(Renumbered - Change Notice 2)

Parameters Monitored or Inspected (Element 3) and Detection of Aging Effects (Element 4)

6. (Hydrant flushing Completed - Change Notice 1 and renumbered - Change Notice 2)
7. Prior to the subsequent period of extended operation, the insulation on the exterior surfaces of the fire water storage tanks (FWSTs) will be permanently removed. Wall thickness measurements will be performed on external tank areas exhibiting unexpected degradation. Refurbishment/recoating will be performed consistent with the severity of the degradation identified and commensurate with the potential for loss of intended function. Inspections of external tank surfaces will be on a refueling cycle frequency.(Renumbered - Change Notice 2 and revised - Change Notice 3)
8. (Strainer flushing completed - Change Notice 1 and renumbered - Change Notice 2)
9. A procedure will be created to provide a Turbine Building oil deluge systems spray nozzle air flow test to ensure that patterns are not impeded by plugged nozzles, to ensure that nozzles are correctly positioned, and to ensure that obstructions do not prevent discharge patterns from wetting surfaces to be protected. (Renumbered - Change Notice 2)

(Old Enhancement #9 was relocated to Enhancement 4 - Change Notice 2)

Detection of Aging Effects (Element4)

10. Procedure will be revised to provide inspection guidance related to lighting, distance and offset for non-ASME Code inspections. The procedure will specify adequate lighting be verified at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two to four feet (or less) will be appropriate. For distant surface inspections, viewing aids such as binoculars may be used. For viewing angles which may prevent adequate inspection, a viewing aid such as an inspection mirror or boroscope should be used.
11. The Unit 1 hydrogen seal oil system deluge sprinkler pipe and Unit 1 station main transformer '1A' deluge sprinkler piping will be reconfigured to allow drainage. As part of the drainage

reconfiguration, visual inspections and wall thickness measurements will be performed on the Unit 1 hydrogen seal oil system deluge sprinkler pipe that does not drain. In addition, wall thickness examination of the Unit 1 main transformer deluge sprinkler piping that does not allow drainage will also be performed as part of the drainage reconfiguration. Piping with unexpected degradation will be replaced.(Revised – Change Notice 3)

12. The program will be revised to require inspections and tests be performed by personnel qualified in accordance with site procedures and programs for the specified task. (Added Change Notice 2)

13. Procedures will be revised to require when degraded coatings are detected by internal coating inspections, acceptance criteria and corrective action recommendations consistent with the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers and Tanks (B2.1.28) program are followed in lieu of NFPA 25 section 9.2.7 (1), (2), and (4). When interior pitting or general corrosion (beyond minor surface rust) is detected, tank wall thickness measurements are conducted as stated in NFPA 25 Section 9.2.7(3) in vicinity of the loss of material. Vacuum box testing as stated in NFPA 25 Section 9.2.7(5) is conducted when pitting, cracks, or loss of material is detected in the immediate vicinity of welds. (Added Change Notice 2)

14. The activity of the jockey pump will be monitored consistent with the "detection of aging effects" program element of NUREG-2191, Section XI.M41. (Added - Set 3 RAIs)

Detection of Aging Effects (Element4) and Acceptance Criteria (Element 6)

15. Procedures will be revised to address recurring internal corrosion with the use of Low Frequency Electromagnetic Technique (LFET) or a similar technique on 100 feet of piping during each refueling cycle to detect changes in the pipe wall thickness. LFET screening or a similar technique will also be performed on accessible interior fire water storage tank bottoms during periodic inspections. The procedure will specify thinned areas found during the LFET screening be followed up with pipe wall thickness examinations to ensure aging effects are managed and wall thickness is within acceptable limits. In addition to the pipe wall thickness examination, the performance of opportunistic visual inspections of the fire protection system will be required whenever the fire water system is opened for maintenance.

Operating Experience Summary

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

1. In January 2012, an Engineering walkdown of the fire protection piping header along the north wall of the Unit 2 Turbine Building revealed a potential leak location on the supply line to a hose rack. The flanged connection and straight pipe were removed and replaced.

2. In January 2012, a section of 2-inch fire protection "drop" piping in the Turbine Building developed a leak. The investigation for extent of condition and determination for the extent of fire protection piping to be inspected and replaced, as necessary, involved inspections of three locations in the Turbine Building and three locations in the Auxiliary Building. Microbiologically induced corrosion (MIC) was evident in many locations, but the extent of corrosion was not as severe in the Auxiliary Building as it was in the Turbine Building. Despite the less severe corrosion in the Auxiliary Building, the three segments of piping that were inspected were replaced. Similarly, one of the three segments of piping in the Turbine Building was replaced.

   A capital project was proposed for a multi-year process of replacing segments of 2-inch, 4-inch, and 10-inch piping in the Turbine Building. The initial phase that was completed included replacing 200 feet of ten inch piping in the Turbine Building. Additional phases were proposed, and described in the Fire Protection Strategic Plan. See April 2013 and November 2015 operating experience.

3. In June 2012, during inspection of Auxiliary Building fire protection piping minor sediment was discovered in the supply header to the Unit 1 cable tunnel sprinklers. Debris and MIC nodules were discovered inside a spool piece and accessible four inch piping. The sediment and debris were removed, the visual inspection was performed, and the blind flanges and spool pieces were replaced. The necessary pipe replacement is included in the Fire Protection Strategic Plan.

4. In March 2013, NRC Information Notice 13-06, "Corrosion in Fire Protection Piping Due to Air and Water Interaction", identified industry operating experience involving the loss of function of fire protection water systems due to the potential for adverse air and water interactions in pre-action and dry-pipe systems. Engineering evaluated the potential for similar adverse conditions and associated degradation in deluge systems at Surry Power Station that are periodically flow tested. Subsequently, in January 2018, a walkdown was performed to confirm that plant design specifications on drainage features for piping downstream of all in-scope pre-action and deluge valves in the fire protection system continued to be in effect. Two locations, one relating to main transformer 1A and one relating to Unit 1 generator hydrogen seal oil system, were identified as having a potential for adverse air and water interactions and entered into the corrective action program.

5. In April 2013, a section of two 10-inch fire protection system piping in the Turbine Building developed a leak. A walkdown of six locations was performed to determine extent of condition in the Turbine Building and the Auxiliary Building. MIC was evident in four locations, but the extent of corrosion in the Auxiliary Building was not as severe. Replacement of 4-inch and 10-inch fire protection header is a like-for-like replacement. The replacement of the Turbine Fire Protection Header was split into four different phases. One phase was to be accomplished each year. The second phase is planned to replace approximately 400 feet of ten-inch header pipe and 200 feet of two-inch hose station pipe. The necessary pipe replacement is included in the Fire Protection Strategic Plan.

6. In February 2014, visual and volumetric inspections were performed for Fire Protection/domestic water storage tank 1A to determine the extent of additional degradation that had occurred since similar inspections were completed in December 2008. The most significant degradation was noted on the tank floor. The result of the visual inspection was that coating degradation was continuing, and that some bare metal was evident. Similarly, volumetric examinations found additional thinning for the tank floor. Follow-up visual examinations were performed in August 2018 and follow-up wall thickness examinations were performed in March 2019. Prior wall thickness measurements were confirmed to be attributed to laminations that existed from original steel plate fabrication. An engineering evaluation projected the tank floor plate would maintain acceptable wall thickness thoughout the subsequent period of extended operation. Work orders were generated to refurbish/recoat the FWST interior surfaces prior to the subsequent period of extended operation.

7. In August 2014, visual and volumetric inspections were performed for Fire Protection/domestic water storage tank 1B to determine the extent of additional degradation that had occurred since similar inspections were completed in December 2008. The most significant degradation was noted on the tank floor. Follow-up visual examinations were performed in August 2018 and follow-up wall thickness examinations were performed in March 2019. Prior wall thickness measurements were confirmed to be attributed to laminations that existed from original steel plate fabrication. An engineering evaluation projected the tank floor plate would maintain acceptable wall thickness thoughout the subsequent period of extended operation. Work orders were generated to refurbish/recoat the FWST interior surfaces prior to the subsequent period of operation.

8. In September 2014, a materials analysis was performed on buried cement lined grey cast iron fire main piping that was fractured during flow testing of hose station valves. The fracture was attributed to a latent material defect in the cast iron. The piping was removed and replaced with an equivalent spool piece. Based on the oxidation along the top segment of the crack, the pipe was cracked for a long period of time. High levels of calcium deposits on the fracture (from the cement lining) indicate that the pipe was partially cracked at the top segment before factory installation of the cement liner (manufacturing process). Material analysis of the pipe determined that the microstructure consisted of graphite flakes that were approximately 75%

ferrite and 25% pearlite. This resulted in a reduction in the supplied material hardness. Failure of pipe was not preventable through maintenance. The failure was caused by ground settling. During the pipe replacement it was observed that there was vertical misalignment between the replacement pipe and the existing buried pipe, which indicated that the buried side piping was exerting a large bending load at the anchor/foundation. This bending load along with the pre-existing crack and lower hardness value caused the pipe fracture. The balance of the failed pipe was found in good condition with no significant loss of cement lining material, corrosion, cracking, fouling, or reduction of pipe interior diameter.

9. In November 2015, an effectiveness review of the Fire Protection Program aging management activity (AMA) (UFSAR Section 18.2.7) was performed. The AMA was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. A comprehensive fire water system assessment recommended a large scale piping replacement of turbine building and auxiliary building piping. The large scale piping replacement project to be performed over multiple refueling outages was identified as a measure to address degradation in carbon steel system piping and to ensure that system intended functions were maintained. Completed and closed phases of this effort have included replacement of approximately 400 feet of 4 inch piping and 200 feet of 2 inch piping in 2014 and approximately 567 feet of 4 inch piping and 303 feet of 2 inch piping in 2015. An additional phase replacing approximately 175 feet of 4 inch piping and 100 feet of 2 inch piping has been completed and is awaiting final testing. Work documents for additional phases are planned and issued for work extending into 2019.

10. In March 2019, results from fire protection system 2500 gpm flow tests with the motor driven fire pump from 2014 through 2019 consistently showed satisfactory system pressure for the corresponding flow rate. The trend from these results does not indicate significant degradation over the five-year interval, particularly considering the two most recent measurements. Results from fire protection system 2500 gpm flow tests with the diesel driven fire pump from 2014 through 2019 also consistently showed satisfactory system pressure for the corresponding flow rate. There is confidence that continued implementation of flow monitoring for the fire protection system using the three year interval required by the Technical Requirements Manual will effectively manage aging prior to a loss of intended function.

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

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

12. In November 2017, as part of oversight reviews of the Fire Protection Program AMA (UFSAR Section 18.2.7), an inconsistency was identified in the performance interval for system integrity demonstration by main drain testing. The test interval had been extended from quarterly to each 18 months but the extended interval had not been incorporated into program documents. An Engineering Assignment to review operating experience to trended performance data to 2011 has been completed with no significant degrading trends observed. The new interval is consistent with the test interval of NFPA 25 (2011 Edition) Table 13.1.1.2 modified by NUREG-2191, Section XI.M27, Table XI.M27-1, Note 10.

13. In January 2018 an aging management program effectiveness review was performed for the Fire Protection Program AMA (UFSAR Section 18.2.7). Information from the summary of that effectiveness review is provided below:

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

    In the past, multiple fire water piping leaks had been identified in the Unit 1 and Unit 2 Turbine Buildings. As a result, a five phase large scale fire protection piping replacement project has been underway since 2015 to replace Turbine Building header piping and hose station piping as well as the Unit 1 and Unit 2 Auxiliary Building Hose station piping. Two of the Turbine Building phases are complete and two are waiting on testing. Phase five includes the remaining scope in the turbine building and the entire scope in the Auxiliary Building and is planned to start in 2018. Once complete, a large majority of the above ground fire protection piping in the plant will have been replaced, including areas where reoccurring leaks were previously identified.

    The fire water/domestic water storage tanks are managed by the Tank Inspection Activities AMA (UFSAR Section 18.1.3); but, are also discussed here for overall fire protection performance considerations. The fire water/domestic water storage tanks were found to have failing internal coatings and loss of material on the tank floors. Estimates for projected useable tank lifetime and evaluations for additional monitoring were performed. Recommendations are being prepared for repair or replacement project considerations.

Multiple operating issues, and obsolescence of the diesel driven fire pump resulted in a design change that replaced the diesel driven fire pump and associated control panel. The new diesel driven fire pump has exhibited substantially improved performance compared to the original fire pump.

Activities to implement NFPA 25, 1998 Edition, Section 2-3.1.1 (1998 edition), testing of sprinklers that have been in service for fifty years have been initiated to prove continued functionality. The Unit 1 and Unit 2 turbine building sprinklers have been sampled and will be tested by 2021, when fifty years of service is reached.

14. July 2019 – Two buried Fire Protection system piping ruptures occurred at the west end of the Old Administration Building and below the road leading to the Turbine Building track bay. Metallurgical examinations were conducted on both sections of piping.

    The first rupture was a 10-foot long longitudinal crack along the bottom surface of the pipe. Cross sections taken through a 4-inch area of the pipe revealed significant corrosion had developed along the area of the crack initiation location.

    The second section of fire protection pipe failed due to a circumferential crack. The cracking appeared to initiate along the bottom of the pipe and may have resulted after the initial longitudinal crack rupture noted above. The initial rupture generated a force and motion that generated the circumferential crack in an area that had excessive external corrosion.

    An opportunistic inspection of a third section of nearby pipe attached to valve 1-FP-92 also identified corrosion pitting on the pipe and valve body.

    Long standing exposure to moist or wet soil resulted in external corrosion and the subsequent reduction in wall thickness at these locations.

    Both ruptured pipe sections were replaced with ductile iron pipe externally coated with bitumastic external coating and internally lined with a cementitious material. Valve 1-FP-92 and connecting piping were also replaced. There were no unusual system leakage observed during restoration of the replaced components.

Recurring Internal Corrosion (RIC)

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

The above examples of operating experience provides objective evidence that the *Fire Water System* program includes activities to perform periodic fire main and hydrant inspections and flushing, sprinkler inspections, functional test, and flow tests to identify loss of material, flow blockage, and loss of coating integrity for in-scope water-based fire protection systems within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Fire Water System* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Appropriate guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Fire Water System* program, following enhancement, will effectively identify aging, and initiate corrective actions, prior to a loss of intended function.

Conclusion

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

guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Fire Water System* program, following enhancement, will effectively identify aging, and initiate corrective actions, prior to a loss of intended function.

Conclusion

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

B2.1.21 Selective Leaching

Program Description

The *Selective Leaching* program is a new condition monitoring program that will manage loss of material of the susceptible materials located in a potentially aggressive environment. The materials of construction for these components may include gray cast iron, ductile iron, and copper alloys (greater than 15% zinc or greater than 8% aluminum).

A one-time inspection of components exposed to closed-cycle cooling water or treated water environments will be conducted when plant-specific operating experience has not revealed selective leaching in these environments. Opportunistic and periodic inspections will be conducted for raw water, waste water, soil, and groundwater environments, and for closed-cycle cooling water or treated water environments when plant specific operating experience has revealed selective leaching in these environments. A sample of 3% of the population or a maximum of ten components per population at each unit will be visually and mechanically (gray cast iron and ductile iron components) inspected. If the inspection conducted for ductile iron in the 10-year period prior to a subsequent period of extended operation (i.e., the initial inspection) meets acceptance criteria, periodic inspections do not need to be conducted during the subsequent period of extended operation for ductile iron.

Periodic destructive examinations of components for physical properties (i.e. degree of dealloying, through-wall thickness, and chemical composition) will be conducted for components exposed to raw water, waste water, soil, and groundwater environments or for closed-cycle cooling water or treated water environments when plant specific operating experience has revealed selective leaching in these environments. For sample populations with greater than 35 susceptible components at each unit, two destructive examinations will be performed for that population. In addition, for sample populations with less than 35 susceptible components at each unit, one destructive examination will be performed for that population. For opportunistic and periodic inspections, the number of visual and mechanical inspections may be reduced by two for each component that is destructively examined beyond the minimum number of destructive examinations recommended for each sample population. For one-time inspections, the number of visual and mechanical inspections maybe reduced by two for each component that is destructively examined for each sample population.

For two unit sites the <u>periodic</u> visual and mechanical inspections can be reduced from ten to eight because the operating conditions and history at each unit are sufficiently similar (e.g., flowrate, chemistry, temperature, excursions) such that aging effects are not occurring differently between the units. Past power up-rates were implemented for both units at approximately the same time. Historically, water chemistry conditions between the two units have been very similar. The raw water source for both units is the James River. Emergency diesel generator runs are managed to equalize total run times among the diesels, so as to equalize wear and aging. Operating experience for each unit demonstrates no significant difference in aging effects of systems in the scope of this program between the two units.

~~External surfaces of buried components that are coated consistent with the *Buried and Underground Piping and Tanks* program (B2.1.27) are excluded from the sample population.~~

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

Inspection results will be 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. The acceptance criteria are:

- For copper-based alloys, no noticeable change in color from the normal yellow color to the reddish copper color or green copper oxide,
- For gray cast iron and ductile iron, the absence of a surface layer that can be easily removed by chipping or scraping or identified in the destructive examinations,
- The presence of no more than a superficial layer of dealloying, as determined by removal of the dealloyed material by mechanical removal, and
- The components meet system design requirements such as minimum wall thickness, when extended to the end of the subsequent period of extended operation.

When the acceptance criteria are not met such that it is determined that the affected component should be replaced prior to the end of the subsequent period of extended operation, additional inspections will be performed. 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. Extent of condition and extent of cause analysis will include evaluation of difficult-to-access surfaces if unacceptable inspection findings occur within the same material and environment population. The timing of the additional inspections is based on the severity of the degradation identified and is commensurate with the potential for loss of intended function.

NUREG-2191 Consistency

The *Selective Leaching* program is a new program that, when implemented, will be consistent with NUREG-2191, Section XI.M33, Selective Leaching.

Exception Summary

None

Enhancements

None

Operating Experience Summary

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

1. In Spring 1988, inspection of butterfly valves located in the main condenser inlet and outlet piping and in the service water piping associated with the component cooling heat exchangers identified degradation due to graphitic corrosion. IE Notice 84-71 (IEN 84-71) "Graphitic Corrosion of Cast Iron in Salt Water," informed licenses of a potentially significant corrosion problem in salt or brackish water environments. Unit 1 and Unit 2 are located on the salinity line of the James River. This water falls within the brackish category. Both units were designed with a number of cast iron components in the circulating water and service water systems. In response to IEN 84-71, a graphitic corrosion evaluation was performed. The evaluation resulted in the examination of a large sample of components, valves, strainers, and pumps which revealed various degrees of graphitic corrosion. Wall thickness measurements were obtained by ultrasonic testing and verified by mechanical measurements. Destructive measurements were made on some valves. The conclusion of the evaluation was that various valves in the circulating water and service water system would be replaced. The originally installed butterfly valves were uncoated gray cast iron. Due to the brackish water environment, these valves had reduced wall thickness due to graphitic corrosion. In order to ensure seismic qualification, the valves were replaced with valves manufactured from ductile iron due to its mechanical properties. In order to provide extended service life, the wetted portion of the ductile iron (valve disc and body inside surface) had a liquid epoxy coating applied.
2. In January 1996, a materials analysis was performed of the inlet end and approximately five inches of a vacuum priming seal recirculating pump heat exchanger. The inlet end of the heat exchanger was degraded as a result of flow accelerated corrosion. Cross sections taken at the tube to tubesheet interface also revealed signs of dealloying of the copper-zinc tubesheet on the service water side. A definite decrease in the percentages of zinc was detected in these areas. The tubes appeared to be a copper-nickel alloy with a small amount of iron and manganese present. The six originally installed heat exchanger assemblies with copper-nickel alloy tubes and copper-zinc tubesheets were replaced with heat exchanger assemblies with 316 stainless steel tubes and 316L stainless steel tubesheets. To minimize tube fouling, corrosion damage and tube leaks experienced by service water, the heat exchangers were removed from the turbine building service water subsystem by a design change in 1997 and are now cooled by bearing cooling water.

3. In October 2006, circulating water system inlet motor operated valve (MOV) butterfly valves were inspected and found to have numerous coating failures and valve body corrosion degradation. The valves were made from cast A536 ductile iron. The corrosion damage was described as galvanic and graphitic corrosion due to coating failure. A design modification replaced the circulating water Inlet MOV valves with new valves manufactured from a material not susceptible to selective leaching, passivated 316L stainless steel and no problems have been identified since replacement.
4. In 2010, graphitic corrosion was evident when two bearing cooling heat exchanger service water valves, gray cast iron, ASTM A 126, were found to have metal loss after about fifteen years of in service operation. Neither valve had through-wall leakage. The replacement valves are manufactured of ASTM A-536 ductile iron and were coated prior to installation. Replacement work orders were established to replace the valves every fifteen years. The component cooling heat exchanger service water inlet valves are also coated ductile iron valves that were replaced during the fall 2013 Unit 1 refueling outage. The old valves were observed to have limited coating degradation and no noticeable metal loss. Based on engineering observations, ductile iron has exhibited a better performance in service water applications.

The above examples of operating experience provide objective evidence that the *Selective Leaching* program will include activities to perform visual and mechanical inspections or destructive examinations to identify loss of material for piping, valve bodies and bonnets, pump casings, and heat exchanger components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Selective Leaching* program will be evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements will be provided for locations where aging effects are found. The program will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the implementation of the *Selective Leaching* program will effectively manage aging prior to a loss of intended function. Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

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

B2.1.25 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

Program Description

The *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program is an existing condition monitoring program that manages loss of material, cracking, reduction of heat transfer, and flow blockage of metallic components. The program also manages hardening or loss of strength, loss of material, cracking or blistering, and flow blockage of polymeric components. This program consists of visual inspections of accessible internal surfaces of piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components, and other components exposed to air, condensation, diesel exhaust, fuel oil, gas, lubricating oil, and any water environment. Aging effects associated with items (except for elastomers) within the scope of the *Open-Cycle Cooling Water System* program (B2.1.11), *Closed Treated Water Systems* program (B2.1.12), and *Fire Water System* program (B2.1.16) are not managed by this program.

Inspections of metallic components monitor for visible evidence of loss of material. Indicators of aging effects for metallic components include corrosion and surface imperfections; loss of wall thickness; flaking or oxide-coated surfaces; debris accumulation on heat exchanger tube surfaces; and accumulation of particulate fouling, biofouling, or macro fouling.

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

Inspections of polymeric and elastomeric components monitor for changes in material properties or loss of material. Indicators of loss of material and changes in material properties include surface cracking, crazing, scuffing, loss of sealing, dimensional change, loss of wall thickness, discoloration, exposure of internal reinforcement, hardening, and blistering. Physical manipulation or pressurization will be used to augment the visual examinations conducted under this program in order to detect hardening or loss of strength.

The internal inspections are performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. At a minimum, in each 10-year period during the subsequent period of extended operation, a representative sample of 20% of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of nineteen components per population at each unit will be inspected.

Where the sample size is not based on the percentage of the population, it is acceptable to reduce the total number of inspections to nineteen components per population at each unit. The reduced total number of inspections is acceptable because the operating conditions and history at each unit are sufficiently similar (e.g., flowrate, chemistry, temperature, excursions) such that aging effects are not occurring differently between the units. Past power up-rates were implemented for both units at approximately the same time. Historically, water chemistry conditions between the two units have been very similar. The raw water source for both units is the James River. Emergency diesel generator runs are managed to equalize total run times among the diesels, so as to equalize wear and aging. Operating experience for each unit demonstrates no significant difference in aging effects of systems in the scope of this program between the two units.

If any inspections do not meet the acceptance criteria, additional inspections will be conducted, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (i.e., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the next refueling outage interval.

Where practical, the inspections will focus on the bounding or lead components most susceptible to aging because of time in-service, and severity of operating conditions. Opportunistic inspections will continue in each period even if the minimum number of inspections has been conducted.

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

Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the subsequent period of extended operation. For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions.

NUREG-2191 Consistency

The *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components.

Exception Summary

None

Enhancements

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

Parameters Monitored/Inspected (Element 3) and Detection of Aging Effects (Element 4)

1. Procedures will be revised to require inspection of metallic components for flaking or oxide-coated surfaces.
2. Procedures will be revised to require inspection of elastomeric and flexible polymeric components for the following:
    a. Surface crazing, scuffing, loss of sealing, blistering, and dimensional change (e.g., "ballooning" and "necking")
    b. Loss of wall thickness
    c. Exposure of internal reinforcement (e.g., reinforcing fibers, mesh, or underlying metal) for reinforced elastomers
3. Procedures will be revised to specify that visual inspection of elastomeric and flexible polymeric components is supplemented by tactile inspection to detect hardening or loss of suppleness. The minimum surface area for tactile inspections will be at least 10% of the accessible surface area.

Detection of Aging Effects (Element 4)

4. Procedures will be revised to provide non-ASME Code inspection guidance related to lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. The procedure will specify adequate lighting be verified at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two feet or less will be appropriate. For viewing angles which may prevent adequate inspection, a viewing aid such as an inspection mirror or boroscope should be used. For internal inspections, accessible surfaces will be inspected. If inspecting piping internal surfaces, a minimum of one linear foot will be inspected, if accessible. Cleaning will be performed, as necessary, to allow for a meaningful examination. If protective coatings are present, the procedure will require the condition of the coating to be documented.
5. Procedures will be revised to specify that follow-up volumetric examinations are performed where irregularities that could be indicative of an unexpected level of degradation are detected for steel components exposed to raw water, raw water (potable), or waste water.

6. A new procedure will be developed to specify that in each 10-year period during the subsequent period of extended operation, the minimum number of inspections is completed for the various sample populations (each material, environment, and aging effect combination). If opportunistic inspections will not fulfill the minimum number of inspections by the end of each 10-year period, the program owner will initiate work orders as necessary to request additional inspections. A representative sample of 20% of the population (defined as components having the same material, environment, and aging effect combination) or a maximum of nineteen components per population at each unit will be inspected. The new procedure will specify that the inspections focus on the bounding or lead components most susceptible to aging due to time in service and severity of operating conditions.

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

7. A new procedure will be developed to evaluate and project the rate of any degradation until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The inspection sampling bases (e.g., selection, size, frequency) will be adjusted as necessary based on the projection.

Acceptance Criteria (Element 6)

8. A new procedure will be developed to specify that, where practical, acceptance criteria are quantitative (e.g., minimum wall thickness). For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions.

Corrective Actions (Element 7)

9. A new procedure will be developed to specify that additional inspections will be performed if any sampling-based inspections do not meet the acceptance criteria, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination are inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the next refueling outage interval.

Operating Experience Summary

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

1. In January 2009, a leak was identified in a raw water vacuum priming elbow servicing a Unit 1 component cooling heat exchanger. The condition was determined to be pitting due to microbiologically induced corrosion (MIC). The pipe section was removed and replaced. A separate condition report written at the same time documented another leak at a different location in the same section of piping. Three separate through wall leaks were noted on this section of piping and documented on the two condition reports. To provide more information as to extent of condition, another section of vacuum priming pipe on a different component cooling heat exchanger was removed, and showed evidence of MIC, although not through wall. Engineering recommended creation of preventive maintenance items to replace the vacuum priming piping with similar configuration to the MIC-damaged sections on the four Unit 1 component cooling heat exchangers every ten years to prevent future through wall leaks. The new preventive maintenance items were approved in October 2010.
2. In March 2012, during performance of a preventive maintenance activity, it was identified that the housing for an air handling unit was degraded. The internal condition of the housing showed corrosion of the metal. The unit was subsequently replaced as part of a design change to rectify persistent ventilation degradation and equipment obsolescence issues. The design change replaced the major mechanical components of the Unit 1 and Unit 2 cable spreading room ventilation systems and repaired associated ductwork.
3. In May 2013, Engineering performed non-destructive examination on a length of Unit 2 recirculation spray heat exchanger service water vent piping. An elbow in the length of piping showed significant wall thinning. This piping is vented to atmosphere, but is temporarily fully wetted with service water when flow testing the recirculation spray heat exchangers. Quarterly ultrasonic testing of the piping was performed to monitor the progression of thinning until the piping was replaced in the next outage. Inspection during the replacement of the piping documented exfoliation due to corrosion. This is an example of recurring internal corrosion in the service water system.

4. In May 2015, discharge piping in the Unit 1 Turbine Building from plumbing system sump pumps was identified to have several leaks at a threaded fitting at a rate of four to five gallons per minute. The fitting material is cast iron exposed to waste water. The sump liquid pH was determined to be neutral, so the cause was attributed to corrosion from stagnant water over time. Other recent examples of leaks in plumbing system piping at fittings have also been noted. Soft patch repairs were made to the leaks, and work orders initiated to replace the piping. This is an example of recurring internal corrosion in the plumbing system.

5. In December 2015, an effectiveness review was performed of the Work Control Process Activity (UFSAR Section 18.2.19). The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience activity elements. A sample of completed as-found inspection forms was reviewed and identified that the documentation of as-found inspections was inconsistent and needed improvement.

   As a corrective action, training of mechanical maintenance personnel on expectations for properly documenting as-found conditions was conducted. An additional corrective action that recommended enhancement of the as-found inspection form was closed administratively. This operating experience is revisited in the January 2018 AMP effectiveness review. Due to the need for additional improvements noted during the January 2018 AMP effectiveness review, a condition report was entered into the Corrective Action Program.

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

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

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

7. In November 2017, as part of oversight review activities, the Work Control Process Activity (UFSAR Section 18.2.19) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

8. In January 2018, an aging management program effectiveness review was performed of the Work Control Process Activity (UFSAR Section 18.2.19). Information from the summary of that effectiveness review is provided below:

   The Work Control Process Activity plans and conducts testing and maintenance activities, both preventive and corrective. Visual inspections are conducted of the internal surfaces of plant components and adjacent piping that are in the scope of license renewal to monitor for aging effects such as cracking and loss of material. Potential age-related degradation conditions are recorded on "as-found" inspection forms and dispositioned as necessary in the Corrective Action Program. A review was performed of station operating experience identified via the Work Control Process Activity, including conditions identified in the Corrective Action Program from 2006 through 2017.

   While the automatic inclusion of the as-found inspection form in work packages ensures that inspections are performed on in-scope components, a review of a sampling of completed inspection forms throughout the period from 2006 to 2017 showed that inspection personnel are not consistent in the level of detail provided on the form when recording observed conditions. A self-assessment of the License Renewal program documented the issue of inconsistent level of detail on as-found inspection forms in 2015. This operating experience is discussed in item number five above. Corrective actions completed as a result of this Condition Report do not appear to have been effective.

   A sample of as-found inspection forms from March to June 2017 (after the corrective actions were completed) was reviewed and contained the following typical discrepancies:

   - Condition Report numbers not appropriately documented on the inspection sheets concerning discovered aging effects
   - Aging effects not described in detail and documented in the inspection sheet notes section
   - Aging effects table not filled out adequately
   - License Renewal inspection sheets inappropriately dispositioned

   To improve program effectiveness, the following will be addressed and documented during the next aging management program effectiveness review:

   - Investigation and evaluation of inspection results and corrective actions from a sample population of License Renewal equipment work orders
   - Clarification of procedural guidance on inspection parameters including documentation of aging effects
   - Re-training of inspection personnel (current staffing and maintenance of this population of inspectors)
   - Re-training of personnel reviewing inspection forms (current staffing and maintenance of this population of reviewers)

A condition report has been generated in the Corrective Action Program to document and track implementation of these corrective actions.

Recurring Internal Corrosion (RIC)

Recurring internal corrosion, including through-wall failures due to pitting and general corrosion, has been observed in the service water and plumbing systems. Occurrences in the service water system have been noted over a period from 2007 to 2013. Occurrences in the plumbing system have been noted over a period from 2011 to 2018. Corrective actions have been taken previously, and additional actions have been initiated as noted below to minimize the likelihood of piping and component degradation due to pitting and general corrosion in systems monitored by the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program (B2.1.25). Future occurrences of RIC will be documented in accordance with the Corrective Action Program.

Corrective actions include:

- Sections of service water piping not within the scope of GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment," that have documented leaks in the past due to corrosion of carbon steel from a raw water environment have been replaced. Opportunistic inspections of susceptible piping and components will be performed when the system boundary is opened. Periodic system walkdowns in accordance with plant procedure will monitor for leakage. Additional corrective actions will be determined via the Corrective Action Program if significant loss of material is detected.
- Work orders have been created to replace affected portions of the plumbing system piping along an approximately 77 foot length in the Unit 1 Turbine Building basement that have documented leaks from corrosion due to stagnant water in the lines. Opportunistic inspections of susceptible piping and components in other portions of the system within the scope of subsequent license renewal will continue to be performed when the system boundary is opened.

Recurring internal corrosion has also been observed in various lined or coated components, such as the main condenser channel heads and the 96 inch circulating water discharge piping. The aging effects of internally coated/lined surfaces are managed by the *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28). Specific operating experience examples and corrective actions that discuss such aging effects are documented in the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program.

The above examples of operating experience provide objective evidence that the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program includes activities to perform opportunistic inspections to identify loss of material, cracking, reduction of heat transfer, and flow blockage of metallic components. The program also includes activities to perform opportunistic inspections to identify hardening or loss of strength, loss of material, cracking or blistering, and flow blockage of polymeric components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

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

B2.1.27 Buried and Underground Piping and Tanks

Program Description

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

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

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

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

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

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

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

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

NUREG-2191 Consistency

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

Exception Summary

None

Enhancements

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

Preventive Actions (Element 2)

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

2. (Completed Change Notice 2)

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

Preventive Actions (Element 2) and Detection of Aging Effects (Element 4)

4. Procedures will be revised to require uncoated buried stainless steel tubing segments in the fuel oil system be inspected prior to the subsequent period of extended operation. After inspection, each uncoated stainless steel segment will be coated consistent with Table 1 of NACE SP0169-2007, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems" (Added - Set 1 RAIs) (Revised - Set 3 RAIs)

5. A cathodic protection system will be installed for protection of the 24-inch service water piping at the Low Level Intake Structure five years before entering the subsequent period of operation. (Added - Set 3 RAIs)

6. A cathodic protection system will be installed for protection of each unit's buried carbon steel condensate system and auxiliary feedwater system piping from the emergency condensate storage tank and the emergency condensate makeup tank to the service building five years before entering the subsequent period of operation. (Added - Change Notice 4)

Detection of Aging Effects (Element 4)

7. Procedure(s) will be developed to perform a one-time inspection (one excavation) for evidence of concrete aging (below grade) associated with either the Unit 1 or Unit 2 High Level Intake Structures, or the south side of the Turbine Building, or the Fire Water Pump House. For the selected structure, a minimum 50 ft^2 concrete surface area below the frost line will be inspected by the one-time inspection. The procedure will require that, as a surrogate location, the evaluation of the one-time inspection results also include evaluation of the acceptability of the eight inaccessible 96-inch CW pipes located between the High Level Intake Structures and the Turbine Building using the guidance in ACI 349-3R. (Added - Change Notice 4)

Acceptance Criteria (Element 6)

8. Procedures will be revised to specify that cathodic protection surveys use the -850mV polarized potential, instant off criterion specified in NACE SP0169-2007 for steel piping acceptance criteria unless a suitable alternative polarization criteria can be demonstrated. Alternatives will include the -100mV polarization criteria, -750mV criterion (soil resistivity is less than 100,000 ohm-cm), -650mV criterion (soil resistivity is greater than 100,000 ohm-cm), or verification of less than 1 mpy loss of material rate.

   The external loss of material rate is verified:

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

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

When using the electrical resistance corrosion rate probes:

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

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

Operating Experience Summary

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

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

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

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

effectiveness of scheduling and tracking, and program optimization based on inspection results.

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

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

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

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

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

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

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

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

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

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

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

Conclusion

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

APPENDIX C

C1 INTRODUCTION

The *PWR Vessel Internals* program (B2.1.7) is an existing condition monitoring program that manages cracking, loss of material, loss of fracture toughness, change in dimensions due to void swelling, and loss of pre-load for the reactor vessel internals (RVI). The aging effect of cracking includes stress corrosion cracking (SCC), primary water stress corrosion cracking (PWSCC), irradiation-assisted stress corrosion cracking (IASCC), and cracking due to fatigue/cyclic loading. Degradation due to loss of material can be induced by wear, and loss of fracture toughness is the result of thermal aging and neutron irradiation embrittlement. Potential causes for the aging effect of changes in dimensions are void swelling or distortion, and loss of preload can result from thermal and irradiation-enhanced stress relaxation or creep.

The *PWR Vessel Internals* program (B2.1.7) is based on EPRI Technical Report No. 3002005349, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines," (MRP-227, Revision 1), which is implemented in accordance with Nuclear Energy Institute (NEI) 03-08, "Guideline for the Management of Materials Issues". Certain input information for MRP-227, Revision 1 was obtained from MRP-175 and MRP-191. MRP-175 provides screening criteria for PWR internals materials for each age-related degradation mechanism considered: stress corrosion cracking, irradiation-assisted stress corrosion cracking, wear, fatigue, thermal aging embrittlement, irradiation embrittlement, void swelling, and thermal and irradiation-induced stress relaxation/irradiation creep. The screening criteria provide a basis to either screen in or screen out a component. MRP-191 summarizes the results of screening, categorizing, and ranking for Westinghouse-designed internals components based on susceptibility and significance for age-related degradation.

Per NUREG-2191 and NUREG-2192, MRP-227-A continues to provide the reference basis for the *PWR Vessel Internals* program (B2.1.7) during the subsequent period of operation to 80 years. The reference basis is supplemented with this gap analysis to determine changes required to provide reasonable assurance that aging effects will be managed. MRP-227, Revision 1, the results of the Westinghouse expert panel review summarized in Westinghouse letter LTR-AMLR-17-35, "Transmittal of Preliminary Results from the MRP-191 Expert Panel Review in Support of Subsequent License Renewal for Surry Units 1 and 2", and MRP-2018-022, "Transmittal of MRP-191-SLR Screening, Ranking, and Categorization Results and Interim Guidance in Support of Subsequent License Renewal at U.S. PWR Plants" are the key input references for this gap analysis.

The *PWR Vessel Internals* program (B2.1.7) applies the guidance in MRP-227, Revision 1, for inspecting, evaluating, and, if applicable, dispositioning non-conforming RVI components at Units 1 and 2. The selection of RVI components to be inspected is based on a four-step ranking process that includes the designations of "Primary," "Expansion," "Existing programs" (such as American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section XI, Examination Category B-N-3, examinations of core support structures), and "no additional measures." The program includes expanding examinations (i.e., "Expansion" components) if the observed extent of degradation for the "Primary" components exceeds acceptance criteria.

C2 APPLICABILITY REQUIREMENTS FOR SUBSEQUENT LICENSE RENEWAL

C2.1 BASES PROVIDED BY MRP 2018-022

Engineering analyses and evaluations for developing the updated *PWR Vessel Internals* program (B2.1.7) for SLR utilized several assumptions for the operation of the power plant, as described below. These assumptions have been validated for Surry Units 1 and 2.

(a) Each of the units has operated for 30 years or less with high-leakage core loading patterns (fresh fuel assemblies loaded in peripheral locations) followed by implementation of a low-leakage fuel management strategy for the remaining years of operation. The three limitations that define low-leakage operation for SLR considerations are the same as those used for the initial period of extended operation:

- Heat generation rate figure of merit: $F \leq 68$ watts/cm^3
- Average core power density < 124 watts/cm^3
- Active fuel to fuel alignment pin distance > 12.2 inches

(b) The units have operated for the majority of their lifetimes as base-loaded units and are currently operating as base-loaded (each unit operates at fixed thermal power levels and does not usually vary power on a calendar or load demand schedule).

(c) The units have not implemented design changes beyond those identified in general industry guidance or recommended by the original vendors.

(d) The unit listings of functional components have been confirmed to include the components and material class as listed in the latest revision of MRP-191.

C2.2 KEY FACTORS IMPACTING THE DEVELOPMENT OF MRP-227 FOR SLR

MRP-227-A and MRP-227, Revision 1, were developed for the initial period of extended operation in order to extend the original operating license from 40 years to 60 years. Increasing plant operation time to 80 years could affect the content of the *PWR Vessel Internals* program (B2.1.7) because aging degradation mechanisms for reactor vessel internals components have had additional time to evolve, and because the neutron irradiation fluence for those components has continued to increase.

The eight aging degradation mechanisms that can have an impact on the reactor vessel internals were investigated in detail in MRP-175. The following mechanisms were included:

- Stress corrosion cracking (SCC) [SCC at a weld: SCC-W]
- Irradiation-assisted stress corrosion cracking (IASCC)
- Wear
- Fatigue
- Thermal embrittlement (TE)
- Irradiation embrittlement (IE)
- Void swelling
- Thermal and irradiation-induced stress relaxation or irradiation creep (ISR/IC)

SCC, IASCC, wear, fatigue, and thermal embrittlement are all time-dependent, increasing with additional time spent exposed to the environment. IASCC also has an impact from radiation dose accumulation, since it does not occur at zero or very low dose but does occur at higher doses. IE, ISR/IC, and VS are all dose-dependent, increasing with increased radiation exposure. Some of these effects, particularly IE and TE, typically reach a saturation level after enough dose exposure or time. Increasing the assumed operational time from 60 years to 80 years increases both time of exposure and the accumulated radiation dose. These two parameters were evaluated during the expert panel review for MRP-191.

MRP-175, Revision 1, provided updated screening threshold values for each of the eight aging degradation mechanisms with consideration of recent testing and operating experience, and the extension to 80 years of plant life. The previous MRP-175, Revision 0, screening thresholds were quite conservative and most did not include an impact for the length of time that the component was exposed. For example, SCC was based on the applied stress and the condition of the material and not the length of time that the component was exposed to the applied stress. Thus, only two degradation mechanisms required updates to their screening thresholds: IASCC and fatigue.

The threshold for IASCC required an update because of new laboratory data published since MRP-175, Revision 0 which resulted in a new trend curve for IASCC. The threshold for fatigue required an update due to a combination of additional time for operating to 80 years (i.e., additional fatigue cycles) and incorporation of environmental effects on fatigue, which together resulted in a lower cumulative usage factor (CUF) threshold of 0.036 for the fatigue threshold.

The new trend curve for IASCC in MRP-175, Revision 1 did not impact the screening because the screening criteria used in MRP-191, Revision 0 and Revision 1, were more conservative than the IASCC curve. The SLR expert panel review continued to use the same conservative IASCC screening criteria as MRP-191, Revision 0 and Revision 1. The lower CUF threshold did result in a significantly larger number of screened-in components; however, the expert panel determined that the lower screening criteria did not result in promotion of new lead components for fatigue.

Addressing increases in neutron irradiation dose at 80 years involved calculations specifically for representative Westinghouse-designed plants. To obtain representative dose projections with a reasonable amount of added conservatism, dose projections were generated using a model for a representative 3-loop plant at 72 EFPY. To account for variations in axial and radial power shapes, two different dose projections were generated:

- A flat axial power shape that produced conservative dose projection results above and below the active fuel, and
- A best-estimate and realistic axial power shape that produced dose projection results that were more limiting in the radial direction.

These two dose projections were overlaid and the higher dose at any point was utilized.

Table C2.2-1 provides a summary of parameter screening results for the *PWR Vessel Internals* components which require aging management. Applicable ranges are provided for CUF and maximum neutron fluence values.

Table C2.2-1 Parameter Screening Results

Assembly	Subassembly	Component	Material Category	Material Type/ Grade	Effective Stress ≥ Threshold	Structural Weld	Wear Potential	CUF >0.036	CUF >0.1	Preload Required?	Max Neutron Fluence Region @ 80 Yrs[a]
Upper internals assembly	Control rod guide tube assemblies and flow downcomers	Bolts (Note 3)	Austenitic SS	316 SS	Yes	No	No	Yes	Yes	Yes	1
		C-tubes (Note 3)	Austenitic SS	304 SS	No	No	Yes	Yes	No	No	3
		Guide tube enclosures (Note 3)	Austenitic SS	304 SS	No	Yes	No	Yes	No	No	3
		Flanges - intermediate (Note 3)	Austenitic SS	304 SS	Yes	Yes	No	Yes	Yes	No	1
			Cast Austenitic SS	CF8	Yes	Yes	No	Yes	Yes	No	1
		Flanges - lower	Austenitic SS	304 SS	Yes	Yes	No	Yes	Yes	No	4
			Cast Austenitic SS	CF8	Yes	Yes	No	Yes	Yes	No	4
		Flexureless inserts (Unit 2 only) (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	1
		Flexures (Unit 1 only) (Note 3)	PH Ni-base Alloy	X-750	Yes	No	No	Yes	No	Yes	1
		Guide plates (cards)	Austenitic SS	304 SS	Yes	Yes	Yes	Yes	Yes	No	2
			Cast Austenitic SS	CF8	Yes	Yes	Yes	Yes	Yes	No	2
		Guide tube support pins	PH Ni-base Alloy	X-750 (U-1)	Yes	No	Yes	Yes	Yes	Yes	4
		Guide tube support pins (Note 3)	Austenitic SS	316 SS (U-2)	Yes	No	Yes	Yes	Yes	Yes	4
		Housing plates (Note 3)	Austenitic SS	304 SS	No	No	No	No	No	No	1
			Cast Austenitic SS	CF8	No	No	No	No	No	No	1
		Inserts (Unit 1 only) (Note 3)	Austenitic SS	304 SS	No	No	No	No	No	No	1
			Cast Austenitic SS	CF8	No	No	No	No	No	No	1
		Sheaths (Note 3)	Austenitic SS	304 SS	No	No	Yes	Yes	Yes	No	3

Table C2.2-1 Parameter Screening Results

Assembly	Subassembly	Component	Material Category	Material Type/ Grade	Effective Stress ≥ Threshold	Structural Weld	Wear Potential	CUF >0.036	CUF >0.1	Preload Required?	Max Neutron Fluence Region @ 80 Yrs[a]
Upper internals assembly (cont.)	Control rod guide tube assemblies and flow downcomers (cont'd)	Support pin nuts	Austenitic SS	Alloy 600 (U-1)	Note 1	Note 1	Note 1	Note 1	Note 1	Note 1	Note 1
		Support pin nuts (Note 3)	Austenitic SS	316 SS (U-2)	No	No	No	Yes	No	No	4
	Mixing devices	Mixing devices (Note 3)	Cast Austenitic SS	CF8	No	Yes	No	Yes	No	No	4
	Upper core plate and fuel alignment pins	Fuel alignment pins	Austenitic SS	304 SS	Yes	No	Yes	Yes	No	No	4
		Upper core plate	Austenitic SS	304 SS	Yes	No	Yes	Yes	Yes	No	4
		Upper core plate insert (Note 3)	Austenitic SS	304 SS	No	No	Yes	No	N/A	No	3
		Upper core plate insert bolts (Note 3)	Austenitic SS	316 SS	Yes	No	No	Yes	N/A	Yes	3
		Upper core plate insert locking devices and dowel pins (Note 3)	Austenitic SS	304L SS (Note 2)	No	No	No	Yes	N/A	No	3
		Upper core plate insert locking devices and dowel pins (Note 3)	Austenitic SS	316 SS (Note 2)	No	No	No	Yes	N/A	No	3
	Upper instrumentation conduit and supports	Bolting (Note 3)	Austenitic SS	316 SS	No	No	No	No	No	Yes	1
			Austenitic SS	304 SS	No	No	No	No	No	Yes	1
		Brackets, clamps, terminal blocks, and conduit straps (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	3
			Cast Austenitic SS	CF8	No	No	No	Yes	No	No	3

Table C2.2-1 Parameter Screening Results

Assembly	Subassembly	Component	Material Category	Material Type/ Grade	Effective Stress ≥ Threshold	Structural Weld	Wear Potential	CUF >0.036	CUF >0.1	Preload Required?	Max Neutron Fluence Region @ 80 Yrs[a]
Upper internals assembly (cont.)	Upper instrumentation conduit and supports (cont'd)	Conduit seal assembly: body, tubesheets, tubesheet welds (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	1
		Conduit seal assembly: tubes (Note 3)	Austenitic SS	304 SS	Yes	No	No	Yes	No	No	1
		Conduits (Note 3)	Austenitic SS	304 SS	No	No	No	No	No	No	2
		Flange base (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	1
		Locking caps (Note 3)	Austenitic SS	304L SS	No	No	No	Yes	No	No	1
		Support tubes (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	1
	Upper support column assemblies	Adapters (Note 3)	Austenitic SS	304 SS	No	No	No	No	No	No	1
		Bolts (Note 3)	Austenitic SS	316 SS	Yes	No	No	Yes	No	Yes	4
		Column bases (Note 3)	Cast Austenitic SS	CF8	Yes	No	No	No	No	No	4
		Column bodies (Note 3)	Austenitic SS	304 SS	Yes	No	No	Yes	No	No	2
		Extension tubes (Note 3)	Austenitic SS	304 SS	No	Yes	No	No	No	Yes	1
		Flanges (Note 3)	Austenitic SS	304 SS	No	No	No	No	No	No	1
		Lock keys (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	3
		Nuts (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	1
			Austenitic SS	302 SS	No	No	No	Yes	No	No	1
Upper internals assembly (cont.)	Upper support plate assembly – flat plate design	Upper support plate (Note 3)	Austenitic SS	304 SS	Yes	No	No	Yes	No	No	1
		Upper support ring	Austenitic SS	304 SS	Yes	Yes	No	Yes	Yes	No	1
		Deep beam ribs (Note 3)	Austenitic SS	304 SS	Yes	Yes	No	No	No	No	1
		Deep beam stiffeners (Note 3)	Austenitic SS	304 SS	No	Yes	No	No	No	No	1
		Bolts (Note 3)	Austenitic SS	316 SS	Yes	No	No	Yes	No	Yes	1
		Locking device (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	1

Table C2.2-1 Parameter Screening Results

Assembly	Subassembly	Component	Material Category	Material Type/ Grade	Effective Stress ≥ Threshold	Structural Weld	Wear Potential	CUF >0.036	CUF >0.1	Preload Required?	Max Neutron Fluence Region @ 80 Yrs[a]
Lower internals assembly	Baffle and former assembly	Baffle bolting lock bars (Note 3)	Austenitic SS	304 SS	Yes	No	No	Yes	No	No	6
		Baffle-edge bolts	Austenitic SS	316 SS	Yes	No	No	Yes	Yes	Yes	6
		Baffle plates	Austenitic SS	304 SS	Yes	No	No	Yes	No	No	6
		Baffle-former bolts	Austenitic SS	347 SS	Yes	No	No	Yes	Yes	Yes	6
		Corner bolts	Austenitic SS	347 SS	Yes	No	No	Yes	N/A	Yes	6
		Barrel-former bolts	Austenitic SS	347 SS	Yes	No	No	Yes	Yes	Yes	5
		Former plates	Austenitic SS	304 SS	Yes	No	No	Yes	No	No	6
	Bottom-mounted instrumentation (BMI) column assemblies	BMI column bodies	Austenitic SS	304 SS	Yes	Yes	No	Yes	Yes	No	1
		BMI column bolts (Note 3)	Austenitic SS	316 SS	Yes	No	No	Yes	Yes	Yes	5
		BMI column collars (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	5
		BMI column cruciforms (Note 3)	Cast Austenitic SS	CF8	No	No	No	Yes	No	No	5
		BMI column extension bars (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	5
		BMI column extension tubes (Note 3)	Austenitic SS	304 SS	Yes	Yes	No	Yes	Yes	No	1
		BMI column locking devices (Note 3)	Austenitic SS	304L SS	No	No	No	No	No	No	5
		BMI column nuts (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	Yes	5

Table C2.2-1 Parameter Screening Results

Assembly	Subassembly	Component	Material Category	Material Type/ Grade	Effective Stress ≥ Threshold	Structural Weld	Wear Potential	CUF >0.036	CUF >0.1	Preload Required?	Max Neutron Fluence Region @ 80 Yrs[a]
Lower internals assembly (cont.)	Core barrel	Core barrel flange (surface)	Austenitic SS	304 SS	No	Yes	Yes	Yes	No	No	1
		Core barrel outlet nozzles	Austenitic SS	304 SS	Yes	Yes	Yes	Yes	Yes	No	1
		Lower core barrel flange weld (LFW)	Austenitic SS	304 SS	Yes	Yes	No	Yes	No	No	5
		Lower core barrel axial welds, includes MAW and LAW	Austenitic SS	304 SS	Yes	Yes	No	Yes	No	No	5
		Lower core barrel girth weld~~s~~ (~~includes~~ LGW ~~and LFW~~)	Austenitic SS	304 SS	Yes	Yes	No	Yes	No	No	5
		Upper core barrel flange weld (UFW)	Austenitic SS	304 SS	Yes	Yes	No	Yes	No	No	2
		Upper core barrel axial weld~~s~~ (~~includes~~ UAW)	Austenitic SS	304 SS	Yes	Yes	No	Yes	No	No	2
		Upper core barrel girth weld~~s~~ (~~includes UFW and~~ UGW)	Austenitic SS	304 SS	Yes	Yes	No	Yes	No	No	2
	Diffuser plate	Diffuser plate (Note 3)	Austenitic SS	304 SS	No	No	No	No	No	No	2
	Flux thimble (tubes)	Flux thimble tube plugs (Note 3)	Ni-base Alloy	Alloy 600	No	Yes	No	Yes	No	No	6
		Flux thimbles (tubes)	Ni-base Alloy	Alloy 600	No	Yes	Yes	Yes	No	No	6
	Head cooling spray nozzles	Head cooling spray nozzles (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	1

Table C2.2-1 Parameter Screening Results

Assembly	Subassembly	Component	Material Category	Material Type/ Grade	Effective Stress ≥ Threshold	Structural Weld	Wear Potential	CUF >0.036	CUF >0.1	Preload Required?	Max Neutron Fluence Region @ 80 Yrs[a]
Lower internals assembly (cont.)	Irradiation specimen guides	Irradiation specimen access plug (dowel pin) (Note 3)	Austenitic SS	316 SS	No	No	No	No	No	No	1
		Irradiation specimen access plug (plug) (Note 3)	Austenitic SS	304 SS	No	No	No	No	No	No	1
		Irradiation specimen access plug (spring) (Note 3)	PH Ni-base Alloy	X-750	No	No	No	No	No	No	1
		Irradiation specimen guide (Note 3)	Austenitic SS	304 SS	No	No	Yes	Yes	No	No	2
	Lower core plate and fuel alignment pins	Fuel alignment pins	Austenitic SS	304 SS	Yes	No	Yes	No	No	No	6
		Lower core plate	Austenitic SS	304 SS	Yes	Yes	Yes	Yes	Yes	No	5
	Lower support column assemblies	Lower support column bodies	Cast Austenitic SS	CF8	No	No	No	Yes	No	No	5
		Lower support column bolts	Austenitic SS	316 SS	Yes	No	No	Yes	Yes	Yes	5
		Lower support column bolt locking devices (Note 3)	Austenitic SS	304L SS	No	No	No	Yes	N/A	No	5
		Lower support column nuts (Note 3)	Austenitic SS	304 SS	Yes	No	No	Yes	No	Yes	5
		Lower support column sleeves (Note 3)	Austenitic SS	304 SS	No	No	No	No	No	No	2
	Lower support forging	Lower support forging	Austenitic SS	304 SS	Yes	No	No	Yes	No	No	1

Table C2.2-1 Parameter Screening Results

Assembly	Subassembly	Component	Material Category	Material Type/ Grade	Effective Stress ≥ Threshold	Structural Weld	Wear Potential	CUF >0.036	CUF >0.1	Preload Required?	Max Neutron Fluence Region @ 80 Yrs[a]
	Neutron panels/ thermal shield	Thermal shield bolts (Note 3)	Austenitic SS	316 SS	Yes	No	No	Yes	Yes	Yes	2
		Thermal shield dowels (Note 3)	Austenitic SS	316 SS	No	No	No	Yes	No	No	2
			Austenitic SS	304 SS	No	No	No	Yes	No	No	2
		Thermal shield flexures	Austenitic SS	316 SS	Yes	No	No	Yes	Yes	Yes	2
		Thermal shield flexure bolts (Note 3)	Austenitic SS	316 SS	No	No	No	Yes	N/A	Yes	2
		Thermal shield flexure locking devices and dowel pins (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	N/A	No	2
			Austenitic SS	304L SS	No	No	No	Yes	N/A	No	2
		Thermal shield (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	4
	Radial support keys	Radial support key bolts (Note 3)	Austenitic SS	316 SS	Yes	No	Yes	Yes	No	Yes	1
		Radial support key dowels (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	N/A	No	1
			Austenitic SS	316 SS	No	No	No	Yes	N/A	No	1
		Radial support key lock keys (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	1
		Radial support keys (Note 3)	Austenitic SS	304 SS	Yes	Yes	Yes	Yes	No	No	1
		Radial support keys	Hard Facing Alloy	Stellite	No	No	No	Yes	No	No	1
Lower internals assembly (cont.)	Secondary core support (SCS) assembly	SCS base plate (Note 3)	Austenitic SS	304 SS	No	Yes	No	Yes	No	No	1
		SCS bolts (Note 3)	Austenitic SS	316 SS	Yes	No	No	Yes	No	Yes	1
		SCS energy absorber (Note 3)	Austenitic SS	304 SS	No	No	No	No	No	No	1
		SCS guide post (Note 3)	Austenitic SS	304 SS	No	No	No	No	No	No	1
		SCS housing (Note 3)	Austenitic SS	304 SS	No	No	No	No	No	No	1
		SCS lock keys (Note 3)	Austenitic SS	304 SS	No	No	No	Yes	No	No	1
		Upper and lower tie plates (Note 3)	Austenitic SS	304 SS	Yes	No	No	Yes	Yes	Yes	1

Table C2.2-1 Parameter Screening Results

Assembly	Subassembly	Component	Material Category	Material Type/ Grade	Effective Stress ≥ Threshold	Structural Weld	Wear Potential	CUF >0.036	CUF >0.1	Preload Required?	Max Neutron Fluence Region @ 80 Yrs[a]
Interfacing components	Interfacing components	Clevis insert bolts	PH Ni-base Alloy	X-750	Yes	No	Yes	No	No	Yes	1
		Clevis insert dowels	Ni-base Alloy	Alloy 600	No	No	No	Yes	N/A	No	1
		Clevis insert locking devices (Note 3)	Ni-base Alloy	Alloy 600	No	No	No	Yes	No	No	1
		Clevis inserts (Note 3)	Ni-base Alloy	Alloy 600	Yes	No	Yes	Yes	No	No	1
		Clevis inserts	Hard Facing Alloy	Stellite	No	No	Yes	Yes	No	No	1
		Head and vessel alignment pin bolts (Note 3)	Austenitic SS	316 SS	No	No	No	Yes	No	Yes	1
		Head and vessel alignment pins (Note 3)	Austenitic SS	304 SS	Yes	No	No	Yes	Yes	No	1
		Internals hold-down spring	Austenitic SS	304 SS	Yes	No	Yes	Yes	No	Yes	1
		Upper core plate alignment pins	Austenitic SS	304 SS	Yes	Yes	Yes	Yes	Yes	No	3
			Hard Facing Alloy	Stellite	No	No	Yes	No	N/A	No	3
		Thermal sleeves	Austenitic SS	304 SS	No	No	Yes	No	N/A	No	1
		Thermal sleeve guide funnels (Note 3) Unit 2	Cast Austenitic SS	CF8	No	No	Yes	No	N/A	No	1
		Thermal sleeve guide funnels (Note 3) Unit 1	Austenitic SS	304 SS	No	No	Yes	No	N/A	No	1

a. Fluence Regions:

1) $\Phi t < 1x10^{20}$ n/cm^2

2) $1x10^{20}$ n/cm$^2 \leq \Phi t < 7x10^{20}$ n/cm^2

3) $7x10^{20}$ n/cm$^2 \leq \Phi t < 1x10^{21}$ n/cm^2

4) $1x10^{21}$ n/cm$^2 \leq \Phi t < 1x10^{22}$ n/cm^2

5) $1x10^{22}$ n/cm$^2 \leq \Phi t < 5x10^{22}$ n/cm^2

6) $5x10^{22}$ n/cm$^2 \leq \Phi t$

Notes:

1. Alloy 600 was identified as the material for the support pin nuts at Surry Unit 1. These nuts were replaced as part of the control rod guide tube support pin replacement performed by AREVA. The AREVA evaluation indicates that the Unit 1 support pin nuts are susceptible to age-related degradation
2. The upper core plate insert locking devices are 304L SS and the dowel pins are 316 SS.
3. No additional measures

Intentionally Blank

The initial MRP-227A Inspection and Evaluation guidelines incorporated the experts' knowledge of applicable operating experience up to that time. Operating experience with reactor vessel internals components and materials has generally been positive, a trend which has continued since the original MRP-191, Revision 0, expert panel review. The SLR expert panel considered several relevant developments in operating experience for its review of the components:

- Guide plates/cards: Wear of the guide plates/cards was a known issue for Westinghouse-designed plants during the original MRP-191 expert panel review, with the guide cards being assigned to Category C for wear and then becoming a Primary inspection item in MRP-227-A/Revision 1. Exemption requirements for the guide plates/cards are consistent with MRP-2014-006 and WCAP-17451-P.
- Baffle-former bolts: IASCC degradation of the baffle-former bolts was a known issue for Westinghouse-designed plants during the original MRP-191 expert panel review, with the bolts being assigned to Category C in particular for IASCC and fatigue, and then becoming a Primary inspection item in MRP-227-A / Revision 1. Since the original expert panel review, a more severe iteration of baffle-former bolt degradation has been observed at multiple plants, where large clusters of adjacent bolts fail. This is thought to coincide with an acceleration of the rate of baffle-former bolt failures. The operating experience with baffle-former bolts was considered relevant for not only the baffle-former bolts, but also for similar bolts, such as the lower support column bolts and barrel-former bolts which have similar designs and have accumulated significant radiation dose.
- Reactor vessel head adapter thermal sleeve: Wear has been observed at several Westinghouse-designed plants in the reactor vessel head adapter thermal sleeves, but has not been observed for Surry Units 1 and 2. Unacceptable levels of wear have been observed in several cases, and in 2014, a thermal sleeve had worn through such that it was no longer held in position. Recent operating experience at an international plant indicates that wear of the thermal sleeves can impede the ability to insert a control rod assembly as described in Westinghouse Nuclear Safety Advisory Letter NSAL-18-1, Thermal Sleeve Flange Wear Leads to Stuck Control Rod.
- Clevis insert bolts: SCC degradation of the bolts that hold the clevis inserts in place in Westinghouse-designed plants has been observed at 2 U.S. plants. This has been attributed to the susceptible Alloy X-750 material of the bolts and primary water SCC.
- Clevis inserts and radial support keys: Wear of the alignment surfaces provided by the clevis insert and the radial support keys has been observed in both domestic and international Westinghouse-designed plants. This wear was listed as the focus for the Existing programs inspection included in MRP-227-A/Revision 1.

- Malcomized fuel alignment pins: Surface degradation of fuel alignment pins that were fabricated with a malcomized surface hardening treatment has been observed. This appears as a flaking off of a surface material. This could lead to accelerated wear and loss of material on the surface.
- Brackets, clamps, terminal blocks, and conduit straps: During the SLR expert panel review, it was noted that the clamps included for this grouping have experienced some amount of age-related degradation failures. It was thought that this degradation was likely due to SCC of cold-worked regions created during installation.

C3 SLR SCOPE AND SUSCEPTIBILITY FOR PWR VESSEL INTERNALS COMPONENTS

Initial license renewal implementation of aging management requirements for reactor vessel internals involved completing the following steps. Subsequent license renewal implementation of aging management requirements for the reactor vessel internals involved completing the following steps to ensure complete and accurate inclusion of requirements from MRP-227, Revision 1, which are applicable for a Westinghouse plant:

1. Identify the reactor vessel internals components (within the designated reactor vessel internals assembly and sub-assembly), material, and function requiring aging management.
2. Identify the degradation mechanisms for each of the applicable reactor vessel internals components.
3. Perform a failure modes, effects, and criticality analysis (FMECA) for each of the applicable components.
4. Screen the vessel internals components for degradation and provide categorization with respect to safety and economic consequences.
5. Assign risk and significance of degradation for each applicable component.
6. Determine whether aging management for each applicable component will be designated as a Primary activity, an Expansion activity, or an Existing activity.

C3.1 ASSEMBLY, SUB-ASSEMBLY, COMPONENT, MATERIAL, AND FUNCTION

The reference for the listing of reactor vessel internals components and materials for Surry Unit 1 and Unit 2 that require aging management is Westinghouse letter LTR-AMLR-17-35, "Transmittal of Preliminary Results from the MRP-191 Expert Panel Review in Support of Subsequent License Renewal for Surry Units 1 and 2," Attachment 4. The functions for these components were obtained from the aging management review results documentation for the reactor vessel internals system in Table 3.1.2-2, Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel Internals - Aging Management Evaluation. The component, material, and function information from that table is summarized in Table C3.1-1, Reactor Vessel Internals Sub-assembly Components, Materials, Functions. Table C3.1-1 lists all reactor vessel internals components that are within the scope of subsequent license renewal to confirm that aging effects will be managed for the subsequent period of extended operation. The listing provides compliance with Applicant / Licensee Action Item 2 from Revision 1 of the NRC Safety Evaluation Report for MRP-227, Revision 0 (ML11308A770).

Table C3.1-1 Reactor Vessel Internals Sub-assembly Components, Materials, Functions

Assembly	Subassembly	Component	Material Type/ Grade	Function
Upper internals assembly	Control rod guide tube assemblies and flow downcomers	Bolts (Note 1)	316 SS	Structural support
		C-tubes (Note 1)	304 SS	Structural support
		Guide tube enclosures (Note 1)	304 SS	Structural support
		Flanges - intermediate (Note 1)	304 SS	Structural support
			CF8	Structural support
		Flanges - lower	304 SS	Structural support
			CF8	Structural support
		Flexureless inserts (Unit 2 only) (Note 1)	304 SS	Structural support
		Flexures (Unit 1 only) (Note 1)	X-750	Structural support
		Guide plates (cards)	304 SS	Structural support
			CF8	Structural support
		Guide tube support pins	X-750 (U-1)	Structural support
		Guide tube support pins (Note 1)	316 SS (U-2)	Structural support
		Housing plates (Note 1)	304 SS	Structural support
			CF8	Structural support
		Inserts (Unit 1 only) (Note 1)	304 SS	Structural support
			CF8	Structural support
		Sheaths (Note 1)	304 SS	Structural support
		Support pin nuts	Alloy 600 (U-1)	Structural support
		Support pin nuts (Note 1)	316 SS (U-2)	Structural support
	Mixing devices	Mixing devices (Note 1)	CF8	Structural support
	Upper core plate and fuel alignment pins	Fuel alignment pins	304 SS	Structural support
		Upper core plate	304 SS	Structural support
		Upper core plate insert (Note 1)	304 SS	Structural support
		Upper core plate insert bolts (Note 1)	316 SS	Structural support
		Upper core plate insert locking devices and dowel pins (Note 1) (Note 2)	304L SS	Structural support
		Upper core plate insert locking devices and dowel pins (Note 1) (Note 2)	316 SS	Structural support
	Upper instrumentation conduit and supports	Bolting (Note 1)	316 SS	Structural support
			304 SS	Structural support

Table C3.1-1 Reactor Vessel Internals Sub-assembly Components, Materials, Functions

Assembly	Subassembly	Component	Material Type/ Grade	Function
Upper internals assembly (cont'd)	Upper instrumentation conduit and supports (cont'd)	Brackets, clamps, terminal blocks, and conduit straps (Note 1)	304 SS	Structural support
			CF8	Structural support
		Conduit seal assembly: body, tubesheets, tubesheet welds (Note 1)	304 SS	Structural support
		Conduit seal assembly: tubes (Note 1)	304 SS	Structural support
		Conduits (Note 1)	304 SS	Structural support
		Flange base (Note 1)	304 SS	Structural support
		Locking caps (Note 1)	304L SS	Structural support
		Support tubes (Note 1)	304 SS	Structural support
	Upper support column assemblies	Adapters (Note 1)	304 SS	Structural support
		Bolts (Note 1)	316 SS	Structural support
		Column bases (Note 1)	CF8	Structural support
		Column bodies (Note 1)	304 SS	Structural support
		Extension tubes (Note 1)	304 SS	Structural support
		Flanges (Note 1)	304 SS	Structural support
		Lock keys (Note 1)	304 SS	Structural support
		Nuts (Note 1)	304 SS	Structural support
			302 SS	Structural support
	Upper support plate assembly – flat plate design	Upper support plate (Note 1)	304 SS	Structural support
		Upper support ring	304 SS	Structural support
		Deep beam ribs (Note 1)	304 SS	Structural support
		Deep beam stiffeners (Note 1)	304 SS	Structural support
		Bolts (Note 1)	316 SS	Structural support
		Locking device (Note 1)	304 SS	Structural support
Lower internals assembly	Baffle and former assembly	Baffle bolting lock bars (Note 1)	304 SS	Structural support
		Baffle-edge bolts	316 SS	Structural support
		Baffle plates	304 SS	Flow distribution Structural support
		Baffle-former bolts	347 SS	Structural support
		Corner bolts	347 SS	Structural support
		Barrel-former bolts	347 SS	Structural support
		Former plates	304 SS	Structural support

Table C3.1-1 Reactor Vessel Internals Sub-assembly Components, Materials, Functions

Assembly	Subassembly	Component	Material Type/ Grade	Function
Lower internals assembly (cont'd)	Bottom-mounted instrumentation (BMI) column assemblies	BMI column bodies	304 SS	Structural support
		BMI column bolts (Note 1)	316 SS	Structural support
		BMI column collars (Note 1)	304 SS	Structural support
		BMI column cruciforms (Note 1)	CF8	Structural support
		BMI column extension bars (Note 1)	304 SS	Structural support
		BMI column extension tubes (Note 1)	304 SS	Structural support
		BMI column locking devices (Note 1)	304L SS	Structural support
		BMI column nuts (Note 1)	304 SS	Structural support
	Core barrel	Core barrel flange (surface)	304 SS	Flow distribution Structural support
		Core barrel outlet nozzles	304 SS	Structural support
		Lower core barrel flange weld (LFW)	304 SS	Structural support
		Lower core barrel axial welds (includes MAW and LAW)	304 SS	Structural support
		Lower core barrel girth weld~~s~~ (~~includes~~ LGW ~~and LFW~~)	304 SS	Structural support
		Upper core barrel flange weld (UFW)	304 SS	Structural support
		Upper core barrel axial weld~~s~~ (~~includes~~ UAW)	304 SS	Structural support
		Upper core barrel girth weld~~s~~ (~~includes UFW and~~ UGW)	304 SS	Structural support
	Diffuser plate	Diffuser plate (Note 1)	304 SS	Flow distribution
	Flux thimble (tubes)	Flux thimble tube plugs (Note 1)	Alloy 600	Structural support
		Flux thimbles (tubes)	Alloy 600	Structural support
	Head cooling spray nozzles	Head cooling spray nozzles (Note 1)	304 SS	Structural support

Table C3.1-1 Reactor Vessel Internals Sub-assembly Components, Materials, Functions

Assembly	Subassembly	Component	Material Type/ Grade	Function
Lower internals assembly (cont'd)	Irradiation specimen guides	Irradiation specimen access plug (dowel pin) (Note 1)	316 SS	Structural support
		Irradiation specimen access plug (plug) (Note 1)	304 SS	Structural support
		Irradiation specimen access plug (spring) (Note 1)	X-750	Structural support
		Irradiation specimen guide (Note 1)	304 SS	Structural support
	Lower core plate and fuel alignment pins	Fuel alignment pins	304 SS	Structural support
		Lower core plate	304 SS	Structural support
	Lower support column assemblies	Lower support column bodies	CF8	Structural support
		Lower support column bolts	316 SS	Structural support
		Lower support column bolt locking devices (Note 1)	304L SS	Structural support
		Lower support column nuts (Note 1)	304 SS	Structural support
		Lower support column sleeves (Note 1)	304 SS	Structural support
	Lower support forging	Lower support forging	304 SS	Structural support
	Neutron panels/ thermal shield	Thermal shield bolts (Note 1)	316 SS	Structural support
		Thermal shield dowels (Note 1)	316 SS	Structural support
			304 SS	Structural support
		Thermal shield flexures	316 SS	Structural support
		Thermal shield flexure bolts (Note 1)	316 SS	Structural support
		Thermal shield flexure locking devices and dowel pins (Note 1) (Note 3)	304 SS	Structural support
			304L SS	Structural support
		Thermal shield (Note 1)	304 SS	Structural support
	Radial support keys	Radial support key bolts (Note 1)	316 SS	Structural support
		Radial support key dowels (Note 1)	304 SS	Structural support
			316 SS	Structural support
		Radial support key lock keys (Note 1)	304 SS	Structural support
		Radial support keys (Note 1)	304 SS	Structural support
		Radial support keys	Stellite	Structural support

Table C3.1-1 Reactor Vessel Internals Sub-assembly Components, Materials, Functions

Assembly	Subassembly	Component	Material Type/ Grade	Function
Lower internals assembly (cont'd)	Secondary core support (SCS) assembly	SCS base plate (Note 1)	304 SS	Structural support
		SCS bolts (Note 1)	316 SS	Structural support
		SCS energy absorber (Note 1)	304 SS	Structural support
		SCS guide post (Note 1)	304 SS	Structural support
		SCS housing (Note 1)	304 SS	Structural support
		SCS lock keys (Note 1)	304 SS	Structural support
		Upper and lower tie plates (Note 1)	304 SS	Structural support
Interfacing components	Interfacing components	Clevis insert bolts	X-750	Structural support
		Clevis insert dowels	Alloy 600	Structural support
		Clevis insert locking devices (Note 1)	Alloy 600	Structural support
		Clevis inserts (Note 1)	Alloy 600	Structural support
		Clevis inserts	Stellite	Structural support
		Head and vessel alignment pin bolts (Note 1)	316 SS	Structural support
		Head and vessel alignment pins (Note 1)	304 SS	Structural support
		Internals hold-down spring	304 SS	Structural support
		Upper core plate alignment pins	304 SS	Structural support
			Stellite	Structural support
		Thermal sleeves	304 SS	Structural support
		Thermal sleeve guide funnels (Note 1) Unit 1	304 SS	Structural support
		Thermal sleeve guide funnels (Note 1) Unit 2	CF8	Structural support

Notes:

1 No additional measures
2 The upper core plate insert locking devices are 304L SS and the dowel pins are 316 SS.
3 The thermal shield flexure locking devices are 304L SS and the dowel pins are 304 SS.

C3.2 SAFETY AND ECONOMIC CONSEQUENCE AND RISK CATEGORIZATION

Similar to MRP-227-A and MRP-227, Revision 1, MRP 2018-022 prescribes programs and activities that will assure the long-term safe and reliable operation of PWR vessel internals as they age through 80 years. One difference for this revision of guidelines for the *PWR Vessel Internals* program (B2.1.7) is the separation between effects from relevant economic risks for asset management and the impacts of safety risks. The SLR expert panel review utilized this separation between safety and economic considerations to focus on safety consequences during categorization. Descriptions for the categorization of those considerations are indicated in the following two tables:

Table C3.2-1 Safety Consequence Category Descriptions

Category	Description
None	The component has no screened-in degradation mechanism. No need to assess core damage probability.
Low	Expert panel believes there is no credible means for component failures(s) to cause core damage.
Medium	Expert panel believes the potential exists for core damage as a result of component (or multiple) failure(s) but that the ability to shut down the reactor in a controlled manner remains.
High	Expert panel believes that some core damage could possibly result from failure of the component(s).

Table C3.2-2 Economic Consequence Category Descriptions

Category	Description
None	No or trivial cost
Low	Cost that can be generally handled within the existing plant outage budget and resources (<$5M)
Medium	Cost that exceeds the normal plant outage budget and resources (>$5M)
High	Cost that potentially affects the utility's overall enterprise/financial health (>$20M)

The risk categorizations for safety consequences and economic consequences are summarized in the following two tables:

Table C3.2-3 Safety Consequence Risk Category Descriptions

Category	Description
Category A	Those component items for which aging effects are below the screening criteria. Aging degradation significance is minimal. The initial set of Category A components consists of items for which all degradation mechanisms are screened out. These components are identified as "None" in the appropriate columns of the screening and categorization tables. In addition, the FMECA results can identify additional components for which age-related degradation mechanisms have minimal likelihood to cause failure. These components are also assigned to Category A. This action essentially screens these components out of further consideration for future steps in developing MRP-227 for SLR. Additional components may ultimately be categorized as Category A as discussed in the Category B definition.
Category C	Those "lead" component items for which aging effects are above screening levels. Aging degradation significance is high or moderate. Enhanced/augmented inspections and/or surveillance sampling typically may be warranted to assess aging effects and verify component item safety functionality. These components, for which aging effects are above the threshold values of the screening criteria, are assessed to have moderate to high likelihood of occurrence, and have the potential for significant damage. Moreover, they have not been demonstrated, analytically or by experiment, to be sufficiently damage-tolerant to remain functional relative to the aging degradation mechanism(s) identified.
Category B	Category B items are defined as those component items that also are above screening levels but are not "lead" component items. Aging degradation significance is moderate. Category B component items may require additional evaluations to be shown tolerant of the aging effects with no loss of functionality (i.e., damage tolerant). Non-Category A components that are judged to have moderate susceptibility and potentially significant consequences, such that the effects on function cannot easily be dispositioned by screening, and yet are not considered Category C components, are assigned to Category B. Some of the components included in the Category B list may have been screened in for susceptibility to one or more degradation mechanisms, but the likelihood of occurrence and the implied safety risk were assessed by qualitative expert assessment to be low to moderate. If it is further concluded that the existing 10-year in-service inspection or other in-place aging management plans are sufficient to preclude a safety concern, such components can be reassigned as Category A.

Table C3.2-4 Economic Consequence Risk Category Descriptions

Category	Description
Category A	Those component items for which aging effects are below the screening criteria. Aging degradation significance is minimal. The initial set of Category A components consists of items for which all degradation mechanisms are screened out. These components are identified as "None" in the appropriate columns of the screening and categorization tables. In addition, the FMECA results can identify additional components for which age-related degradation mechanisms have minimal likelihood to cause failure. These components are also assigned to Category A. This action essentially screens these components out of further consideration for future steps in developing MRP-227 for SLR. Additional components may ultimately be categorized as Category A as discussed in the Category B definition.
Category C	Those "lead" component items for which aging effects are above screening levels. Aging degradation significance is high or moderate. Enhanced/augmented inspections and/or surveillance sampling typically may be warranted to assess aging effects and verify component item functionality, and identify extent of repairs that may be required (including likely cost and outage duration impacts). These components, for which aging effects are above the threshold values of the screening criteria, are assessed to have moderate to high likelihood of occurrence, and have the potential for significant economic or reliability consequences. Moreover, they have not been demonstrated, analytically or by experiment, to be sufficiently damage-tolerant to remain functional relative to the aging degradation mechanism(s) identified.
Category B	Category B items are defined as those component items that also are above the screening levels but are not "lead" component items. Aging degradation significance is moderate. Category B component items may require additional evaluations to be shown tolerant of the aging effects with no loss of functionality (i.e., damage tolerant). Non-Category A components that are judged to have moderate susceptibility and potentially significant economic consequences, such that the effects on function cannot easily be dispositioned by screening, and yet are not considered Category C components, are assigned to Category B. Some of the components included in the Category B list may have been screened in for susceptibility to one or more degradation mechanisms, but the likelihood of occurrence and the implied economic risk were assessed by qualitative expert assessment to be low to moderate. If it is further concluded that the existing 10-year in-service inspection or other in-place aging management plans are sufficient to preclude a reliability or functional concern, such components can be reassigned as Category A.

C3.3 FAILURE MODES, EFFECTS, AND CRITICALITY ANALYSIS (FMECA)

The outputs generated by the SLR expert panel review were developed based on a specific set of inputs. Those inputs include the list of components in scope, the materials of fabrication for those components, the calculated neutron fluence and dose, the stress and operating conditions assumed, and the known operating experience and plant modifications.

The following table lists the failure likelihood and consequence (damage likelihood) rankings that were applicable from MRP-191, Revision 0 and Revision 1:

Table C3.3-1 MRP-191, Revision 0/1 SLR Expert Panel Reactor Internals FMECA (Significance) Groups

Failure Likelihood	Consequence (Damage Likelihood)		
	Low	Medium	High
High	2	3	3
Medium	1	2	3
Low	1	1	2
None	0	0	0

The related values of failure likelihood and consequence rankings from MRP-191, Revision 2, are indicated in the following table:

Table C3.3-2 MRP-191, Revision 2 SLR Expert Panel Reactor Internals FMECA (Significance) Groups

Failure Likelihood	Consequence (Damage Likelihood)		
	Low	Medium	High
High	3	3	3
Medium	2	2	3
Low	1	1	2
None	0	0	0

Table C3.3-3 provides the results from the expert panel review. This table lists the following parameters for each of the PWR vessel internals components which requires aging management:

~~Screened-in degradation mechanisms, including the progression of degradation mechanisms from~~ MRP-191, Revision 0; through MRP-191, Revision 1; to MRP-191, Revision 2.

- Likelihood of failure
- Safety consequence
- Economic consequence
- Safety FMECA group
- Economic FMECA group
- Safety consequence risk category
- Economic consequence risk category
- SLR inspection category

Similar to the expert panel outputs documented in MRP-191, Revision 1, the SLR expert panel review resulted in a number of components being assigned to the highest risk category. Some of those assignments were the result of both safety categorization and economic categorization, but more were for economic consequences alone.

Comparing the results from the SLR expert panel review to the previous results from MRP-191, Revision 1, shows that ten components were added to the group of Category C items:

Economic Risk Category C

- Upper core plate
- Brackets, clamps, terminal blocks, and conduit straps
- Baffle-former assembly bracket bolts [Not applicable for SPS]
- Thermal shield flexures
- Clevis insert bolts
- Internals hold-down spring

Safety and Economic Risk Category C

- Baffle-former assembly corner bolts
- Radial support keys (Stellite wear surface)
- Clevis inserts (Stellite wear surface)
- Thermal sleeves

As shown in Table C3.3-3 and summarized in Table C3.3-4, two Category C items from MRP-191, Revision 1, were moved to lower risk categories:

- Control rod guide tube (CRGT) assembly C-tubes
- Flux thimble (tubes)

Revised screening criteria, recent operating experience, and increases in time and neutron dose influenced the above increases in risk category. The decreases in risk category were related to revisions to risk based on actual operational impact, such as for the flux thimble tubes.

Table C3.3-4 provides a comparison of risk categorization between MRP-191, Revision 1, and those developed during the SLR expert panel review.

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a] MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022	Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
Upper internals assembly	Control rod guide tube assemblies and flow downcomers	Bolts (Note 3)	316 SS	None	None	SCC, Fatigue	L	M	L	1	1	A	A	N
		C-tubes (Note 3)	304 SS	Wear	Wear	Wear, Fatigue	M	M	M	2	2	B	B	N
		Guide tube enclosures (Note 3)	304 SS	SCC-W, Wear	SCC-W	SCC-W, Fatigue	L	M	M	1	1	A	A	N
		Flanges - intermediate (Note 3)	304 SS	SCC-W, Fatigue	SCC-W, Fatigue	SCC-W, Fatigue	L	M	M	1	1	A	A	N
			CF8	SCC-W, Fatigue, TE	SCC-W, Fatigue, TE	SCC-W, Fatigue, TE	L	M	M	1	1	A	A	N
		Flanges - lower	304 SS	SCC-W, Fatigue	SCC-W, Fatigue	SCC-W, IASCC, Fatigue, IE	M	M	M	2	2	B	B	P
			CF8	SCC-W, Fatigue, TE, IE	SCC-W, Fatigue, TE, IE	SCC-W, IASCC, Fatigue, TE, IE	M	M	M	2	2	B	B	P
		Flexureless inserts (Unit 2 only) (Note 3)	304 SS	None	None	Fatigue	L	L	L	1	1	A	A	N
		Flexures (Unit 1 only)	X-750	SCC	SCC	SCC, Fatigue	Note 6	Note 6	Note 6	Note 6	Note 6	Note 6	Note 6	N
		Guide plates (cards)	304 SS	SCC-W, Wear, Fatigue	SCC-W, Wear, Fatigue	SCC-W, Wear, Fatigue	H	H	M	3	3	C	C	P
			CF8	--	SCC-W, Wear, Fatigue, TE, IE	SCC-W, Wear, Fatigue, TE	H	H	M	3	3	C	C	P

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a]			Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
				MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022								
Upper internals assembly (cont.)	Control rod guide tube assemblies and flow downcomers (cont'd)	Guide tube support pins	X-750 (U-1)	SCC, Wear, Fatigue, ISR/IC	SCC, Wear, Fatigue, ISR/IC	SCC, IASCC, Wear, Fatigue, IE, ISR/IC	H	L	M	3	3	C	C	X
		Guide tube support pins (Note 3)	316 SS (U-2)	Wear, Fatigue, ISR/IC	Wear, Fatigue, ISR/IC	IASCC, Wear, Fatigue, IE, ISR/IC	L	L	M	1	1	A	A	N
		Housing plates (Note 3)	304 SS	None	None	None	--	--	--	0	0	A	A	N
			CF8	--	TE	TE	L	L	M	1	1	A	A	N
		Inserts (Unit 1 only) (Note 3)	304 SS	None	None	None	--	--	--	0	0	A	A	N
			CF8	--	--	TE	L	L	L	1	1	A	A	N
		Sheaths (Note 3)	304 SS	Wear	Wear	Wear, Fatigue	H	H	M	3	3	C	C	N
		Support pin nuts	Alloy 600 (U-1)	--	--	Note 1	Note 1	Note 1	Note 1	Note 1	Note 1	Note 1	Note 1	X
		Support pin nuts (Note 3)	316 SS (U-2)	None	None	Fatigue, IE	L	L	M	1	1	A	A	N

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a] MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022	Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
Upper internals assembly (cont.)	Mixing devices	Mixing devices (Note 3)	CF8	SCC-W, TE, IE	SCC-W, TE, IE	SCC-W, Fatigue, TE, IE	L	L	M	1	1	A	A	N
	Upper core plate and fuel alignment pins	Fuel alignment pins	304 SS	--	Wear	IASCC, Wear, Fatigue, IE (Note 7)	H	L	M	3	3	B	B	X
		Upper core plate	304 SS	Wear, Fatigue	Wear, Fatigue, IE	IASCC, Wear, Fatigue, IE	M	M	H	2	3	B	C	E
		Upper core plate insert (Note 3)	304 SS	--	--	Wear, IE	M	M	M	2	2	B	B	N
		Upper core plate insert bolts (Note 3)	316 SS	--	--	IASCC, Fatigue, IE, ISR/IC	L	L	M	1	1	A	A	N
		Upper core plate insert locking devices and dowel pins (Note 3)	*304L SS* (Note 2)	--	--	Fatigue, IE	L	L	M	1	1	A	A	N
		Upper core plate insert locking devices and dowel pins (Note 3)	316 SS (Note 2)	--	--	Fatigue, IE	L	L	M	1	1	A	A	N
	Upper instrumentation conduit and supports	Bolting (Note 3)	316 SS	None	None	None	--	--	--	0	0	A	A	N
			304 SS	--	None	None	--	--	--	0	0	A	A	N
		Brackets, clamps, terminal blks, conduit straps (Note 3)	304 SS	None	None	SCC, Fatigue	H	L	H	3	3	B	C	N
			CF8	--	TE	SCC, Fatigue, TE, IE	L	L	H	1	2	A	B	N
		Conduit seal assembly: body, tubesheets, tubesheet welds (Note 3)	304 SS	None	None	SCC, Fatigue	H	M	M	3	3	B	B	N

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a]			Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
				MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022								
Upper internals assembly (cont.)	Upper instrumentation conduit and supports (cont.)	Conduit seal assembly: tubes (Note 3)	304 SS	None	None	SCC, Fatigue	H	M	M	3	3	B	B	N
		Conduits (Note 3)	304 SS	None	None	None	--	--	--	0	0	A	A	N
		Flange base (Note 3)	304 SS	None	None	Fatigue	L	L	M	1	1	A	A	N
		Locking caps (Note 3)	304L SS	None	None	Fatigue	L	L	M	1	1	A	A	N
		Support tubes (Note 3)	304 SS	None	None	Fatigue	L	L	M	1	1	A	A	N
	Upper support column assemblies	Adapters (Note 3)	304 SS	None	None	None	--	--	--	0	0	A	A	N
		Bolts (Note 3)	316 SS	Wear, Fatigue, ISR/IC	Wear, Fatigue, ISR/IC	IASCC, Wear, Fatigue, IE, ISR/IC	L	L	M	1	1	A	A	N
		Column bases (Note 3)	CF8	SCC, TE, IE	SCC, TE, IE	SCC, IASCC, TE, IE	L	L	H	1	2	A	B	N
		Column bodies (Note 3)	304 SS	None	None	SCC-W, Fatigue	L	L	H	1	2	A	B	N
		Extension tubes (Note 3)	304 SS	SCC-W	SCC-W	SCC-W	L	L	H	1	2	A	B	N
		Flanges (Note 3)	304 SS	None	None	None	--	--	--	0	0	A	A	N
		Lock keys (Note 3)	304 SS	None	None	Fatigue	L	L	M	1	1	A	A	N
		Nuts (Note 3)	304 SS	None	None	Fatigue	L	L	M	1	1	A	A	N
			302 SS	--	None	Fatigue	L	L	M	1	1	A	A	N

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a]			Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
				MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022								
Upper internals assembly (cont.)	Upper support plate assembly – flat plate design	Upper support plate (Note 3)	304 SS	None	None	Fatigue	L	L	H	1	2	A	B	N
		Upper support ring	304 SS	SCC-W, Fatigue	SCC-W, Fatigue	SCC-W, Fatigue	L	L	H	1	2	A	B	X
		Deep beam ribs (Note 3)	304 SS	SCC-W	SCC-W	SCC-W	L	L	L	1	1	A	A	N
		Deep beam stiffeners (Note 3)	304 SS	SCC-W	SCC-W	SCC-W	L	L	L	1	1	A	A	N
		Bolts (Note 3)	316 SS	None	None	SCC, Fatigue	L	L	L	1	1	A	A	N
		Locking device (Note 3)	304 SS	--	None	Fatigue	L	L	L	1	1	A	A	N

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a] MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022	Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
Lower internals assembly	Baffle and former assembly	Baffle bolting lock bars (Note 3)	304 SS	IASCC, IE, VS	IASCC, IE, VS	IASCC, Fatigue, IE, VS	H	L	M	3	3	B	B	N
		Baffle-edge bolts	316 SS	IASCC, Wear, Fatigue, IE, VS, ISR/IC	IASCC, Wear, Fatigue, IE, VS, ISR/IC	IASCC, Wear, Fatigue, IE, VS, ISR/IC	H	L	M	3	3	B	C	P
		Baffle plates	304 SS	IASCC, IE, VS	IASCC, IE, VS	IASCC, Fatigue, IE, VS	L	L	L	1	1	A	A	P
		Baffle-former bolts	347 SS	IASCC, Wear, Fatigue, IE, VS, ISR/IC	IASCC, Wear, Fatigue, IE, VS, ISR/IC	IASCC, Wear, Fatigue, IE, VS, ISR/IC	H	M	M	3	3	C	C	P
		Corner bolts	347 SS	--	--	IASCC, Wear, Fatigue, IE, VS, ISR/IC	H	M	M	3	3	C	C	P (added by IG)
		Barrel-former bolts	347 SS	IASCC, Wear, Fatigue, IE, VS, ISR/IC	IASCC, Wear, Fatigue, IE, VS, ISR/IC	IASCC, Wear, Fatigue, IE, VS, ISR/IC	H	L	M	3	3	B	C	E
		Former plates	304 SS	IASCC, IE, VS	IASCC, IE, VS	IASCC, Fatigue, IE, VS	L	L	L	1	1	A	A	P

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a]			Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
				MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022								
Lower internals assembly (cont.)	Bottom-mounted instrumentation (BMI) column assemblies	BMI column bodies	304 SS	SCC-W, IASCC, Fatigue, IE, VS	SCC-W, IASCC, Fatigue, IE, VS	SCC-W, Wear, Fatigue	M	L	L	2	2	B	B	E
		BMI column bolts (Note 3)	316 SS	Fatigue	Fatigue	IASCC, Wear, Fatigue, IE, VS, ISR/IC	M	L	M	2	2	B	B	N
		BMI column collars (Note 3)	304 SS	IASCC, IE, VS	IASCC, IE, VS	IASCC, Fatigue, IE, VS	M	L	L	2	2	B	B	N
		BMI column cruciforms (Note 3)	CF8	IASCC, TE, IE, VS	IASCC, TE, IE, VS	IASCC, Wear, Fatigue, TE, IE, VS	M	L	L	2	2	B	B	N
		BMI column extension bars (Note 3)	304 SS	IASCC, IE, VS	IASCC, IE, VS	IASCC, Fatigue, IE, VS	L	L	L	1	1	A	A	N
		BMI column extension tubes (Note 3)	304 SS	SCC-W, IASCC, Fatigue, IE, VS	SCC-W, IASCC, Fatigue, IE, VS	SCC-W, Fatigue	L	L	L	1	1	A	A	N
		BMI column locking devices (Note 3)	304L SS	None	None	IASCC, IE, VS	L	L	L	1	1	A	A	N
		BMI column nuts (Note 3)	304 SS	IASCC, Wear, Fatigue, IE, VS, ISR/IC	IASCC, Wear, Fatigue, IE, VS, ISR/IC	IASCC, Wear, Fatigue, IE, VS, ISR/IC	L	L	L	1	1	A	A	N

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a] MRP-191, Rev. 0	Screened-in Degradation Mechanisms[a] MRP-191, Rev. 1	Screened-in Degradation Mechanisms[a] Expert Panel [c] / MRP 2018-022	Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
Lower internals assembly (cont.)	Core barrel	Core barrel flange (surface: ~~upper flange weld is included below with upper core barrel girth welds)~~	304 SS	SCC-W, Wear	SCC-W, Wear	SCC-W, Wear, Fatigue	L	M	H	1	2	B	B	X
		Core barrel outlet nozzles	304 SS	SCC-W, Fatigue	SCC-W, Fatigue	SCC-W, Wear, Fatigue	L	M	H	1	2	B	B	N
		Lower core barrel flange weld (LFW) (Note 5)	304 SS	SCC-W, Wear	SCC-W, Wear	SCC-W, Wear, Fatigue	M	M	H	2	3	B	C	E
		Lower core barrel axial welds (includes MAW and LAW)	304 SS	SCC-W, IASCC, IE	SCC-W, IASCC, IE	SCC-W, IASCC, Fatigue, IE, VS	M	M	H	2	3	B	C	E
		Lower core barrel girth welds (-LGW) ~~Note 5~~	304 SS	SCC-W, IASCC, IE	SCC-W, IASCC, IE	SCC-W, IASCC, Fatigue, IE, VS	M	M	H	2	3	B	C	P
		Upper core barrel flange weld (UFW)	304 SS	SCC-W, Wear	SCC-W, Wear	SCC-W, Wear, Fatigue	M	M	H	2	3	B	C	P
		Upper core barrel axial weld~~s~~ (~~includes~~ UAW) (Note 5)	304 SS	SCC-W, IASCC, IE	SCC-W, IE	SCC-W, Fatigue	M	M	H	2	3	B	C	E
		Upper core barrel girth welds (~~includes UFW~~UGW) (Note 5)	304 SS	SCC-W, IASCC, IE	SCC-W, IE	SCC-W, Fatigue	M	M	H	2	3	B	C	~~P~~ E
	Diffuser plate	Diffuser plate (Note 3)	304 SS	None	None	None	--	--	--	0	0	A	A	N

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a]			Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
				MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022								
Lower internals assembly (cont.)	Flux thimble (tubes)	Flux thimble tube plugs (Note 3)	Alloy 600	--	SCC-W, IASCC, IE, VS	SCC-W, IASCC, Fatigue, IE, VS	M	L	L	2	2	B	B	N
		Flux thimbles (tubes)	Alloy 600	--	SCC-W, IASCC, Wear, IE, VS	SCC-W, IASCC, Wear, Fatigue, IE, VS	H	L	L	3	3	B	B	X
	Head cooling spray nozzles	Head cooling spray nozzles (Note 3)	304 SS	None	None	Fatigue	L	L	L	1	1	A	A	N
	Irradiation specimen guides	Irradiation specimen access plug (dowel pin) (Note 3)	316 SS	--	--	None	--	--	--	0	0	A	A	N
		Irradiation specimen access plug (plug) (Note 3)	304 SS	IE	IE	None	--	--	--	0	0	A	A	N
		Irradiation specimen access plug (spring) (Note 3)	X-750	--	--	None	--	--	--	0	0	A	A	N
		Irradiation specimen guide (Note 3)	304 SS	Wear, IE	Wear, IE	SCC-W, Wear, Fatigue	L	L	L	1	1	A	A	N
	Lower core plate and fuel alignment pins	Fuel alignment pins	304 SS	--	IASCC, Wear, IE, VS	IASCC, Wear, IE, VS (Note 7)	H	L	M	3	3	B	B	X (added by IG)
		Lower core plate	304 SS	SCC-W, IASCC, Wear, Fatigue, IE, VS	SCC-W, IASCC, Wear, Fatigue, IE, VS	IASCC, Wear, Fatigue, IE, VS	L	M	H	1	2	A	B	X

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a]			Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
				MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022								
Lower internals assembly (cont.)	Lower support column assemblies	Lower support column bodies	CF8	IASCC, TE, IE, VS	IASCC, TE, IE, VS	IASCC, Fatigue, TE, IE, VS	L	L	L	1	1	A	A	E
		Lower support column bolts	316 SS	--	IASCC, Wear, Fatigue, IE, VS, ISR/IC	IASCC, Wear, Fatigue, IE, VS, ISR/IC	M	L	M	2	2	B	B	E
		Lower support column bolt locking devices (Note 3)	304L SS	--	--	IASCC, Fatigue, IE, VS	L	L	L	1	1	A	A	N
		Lower support column nuts (Note 3)	304 SS	None	None	Fatigue	L	L	L	1	1	A	A	N
		Lower support column sleeves (Note 3)	304 SS	None	None	None	--	--	--	0	0	A	A	N

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a] MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022	Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
Lower internals assembly (cont.)	Lower support forging	Lower support forging	304 SS	None	None	Fatigue	L	M	H	1	2	A	B	E
	Neutron panels/ thermal shield	Thermal shield bolts (Note 3)	316 SS	IASCC, Wear, Fatigue, IE, ISR/IC	IASCC, Wear, Fatigue, IE, ISR/IC	Fatigue, ISR/IC	H	L	L	3	3	B	B	N
		Thermal shield dowels (Note 3)	316 SS	IE	IE	Fatigue	L	L	L	1	1	A	A	N
			304 SS	–	IE	Fatigue	L	L	L	1	1	A	A	N
		Thermal shield flexures	316 SS	–	IASCC, Wear, Fatigue, IE, ISR/IC	SCC-W, Fatigue	M	L	H	2	3	B	C	P
		Thermal shield flexure bolts (Note 3)	316 SS	–	--	Fatigue, ISR/IC	L	L	L	1	1	A	A	N
		Thermal shield flexure locking devices and dowel pins (Note 3) (Note 4)	304 SS	–	--	Fatigue	L	L	L	1	1	A	A	N
			304L SS	–	--	Fatigue	L	L	L	1	1	A	A	N
		Thermal shield (Note 3)	304 SS	IE	IE	SCC-W, Fatigue, IE	L	L	L	1	1	A	A	N

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a] MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022	Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
Lower internals assembly (cont.)	Radial support keys	Radial support key bolts (Note 3)	316 SS	--	Wear	Fatigue	L	L	L	1	1	A	A	N
		Radial support key dowels (Note 3)	304 SS	--	--	Fatigue	L	L	L	1	1	A	A	N
			316 SS	--	--	Fatigue	L	L	L	1	1	A	A	N
		Radial support key lock keys (Note 3)	304 SS	None	None	Fatigue	L	L	L	1	1	A	A	N
		Radial support keys	304 SS	SCC-W, Wear	SCC-W, Wear	SCC-W, Wear, Fatigue	L	M	M	1	1	A	A	N
		Radial support keys	Stellite	--	--	Wear	H	M	M	3	3	C	C	P (added by IG)
	Secondary core support (SCS) assembly	SCS base plate (Note 3)	304 SS	SCC-W	SCC-W	SCC-W, Fatigue	L	L	L	1	1	A	A	N
		SCS bolts (Note 3)	316 SS	None	None	Fatigue	L	L	L	1	1	A	A	N
		SCS energy absorber (Note 3)	304 SS	None	None	None	--	--	--	0	0	A	A	N
		SCS guide post (Note 3)	304 SS	None	None	None	--	--	--	0	0	A	A	N
		SCS housing (Note 3)	304 SS	None	None	None	--	--	--	0	0	A	A	N
		SCS lock keys (Note 3)	304 SS	None	None	Fatigue	L	L	L	1	1	A	A	N
		Upper and lower tie plates (Note 3)	304 SS	--	None	Fatigue	L	L	L	1	1	A	A	N

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a]			Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
				MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022								
Interfacing components	Interfacing components	Clevis insert bolts	X-750	SCC, Wear	SCC, Wear	SCC, Wear	H	L	H	3	3	B	C	P (added by IG)
		Clevis insert dowels	Alloy 600	--	--	Fatigue	M	L	L	2	2	B	B	P (added by IG)
		Clevis insert locking devices (Note 3)	Alloy 600	None	None	Fatigue	L	L	L	1	1	A	A	N
		Clevis inserts	Alloy 600	Wear	Wear	Wear, Fatigue	L	L	H	1	2	A	B	P
			Stellite	Wear	Wear	Wear, Fatigue	H	M	H	3	3	C	C	P
		Head and vessel alignment pin bolts (Note 3)	316 SS	None	None	Fatigue	L	L	L	1	1	A	A	N
		Head and vessel alignment pins (Note 3)	304 SS	None	None	Fatigue	L	L	L	1	1	A	A	N
		Internals hold-down spring	304 SS	Wear	Wear	Wear, Fatigue	H	L	H	3	3	B	C	P
		Upper core plate alignment pins	304 SS	SCC-W, Wear	SCC-W, Wear	SCC-W, Wear, Fatigue	L	L	M	1	1	A	A	X
			Stellite	--	--	Wear	M	L	M	2	2	A	B	X
		Thermal sleeves	304 SS	--	--	Wear	H	H	H	3	3	C	C	P
		Thermal sleeve guide funnels (Note 3) Unit 1	304 SS	--	--	Wear, TE	H	L	L	3	3	B	B	N
		Thermal sleeve guide funnels (Note 3) Unit 2	CF8	--	--	Wear, TE	H	L	L	3	3	B	B	N

a. Degradation mechanisms:
Stress corrosion cracking (SCC) [1A is applicable for SCC welds (SCC-W)]
Irradiation-assisted stress corrosion cracking (IASCC)
Wear
Fatigue (FAT)
Thermal aging embrittlement (TE)
Irradiation embrittlement (IE)
Void swelling (VS)
Thermal and irradiation-induced stress relaxation or irradiation creep (ISR/IC)

b. P = Primary, E = Expansion, X = Existing, N = No additional measures

c. Degradation mechanism added during Expert Panel review as indicated in LTR-AMLR-17-35 and LTR-AMLR-18-4.

Notes:

1. Alloy 600 was identified as the material for the support pin nuts at Surry Unit 1. These nuts were replaced as part of the control rod guide tube support pin replacement performed by AREVA. The AREVA evaluation indicates that the aging degradation mechanisms of concern are SCC and irradiation-enhanced stress relaxation/irradiation-enhanced creep (ISR/IC).
2. The upper core plate insert locking devices are 304L SS, and the dowel pins are 316 SS.
3. No additional measures.
4. The thermal shield flexure locking devices are 304L SS and the dowel pins are 304 SS.
5. MRP-227, Revision 1, added expansion links from the core barrel upper flange weld (UFW) to the lower flange weld (LFW), ~~and to~~ the upper girth weld (UGW), and the upper axial weld (UAW).
6. For Unit 1, Babcock & Wilcox replaced the CRGT support pins and flexures with a modified design fabricated from Alloy X-750 during the CRGT replacement. The MRP-191, Revision 2, expert panel considered the Alloy X-750 flexures to be a Category C component. However, AREVA performed an evaluation of the replacement CRGT assemblies, including the replacement flexures. Section 4.1 of the AREVA report (AREVA Licensing Report ANP-3574, Rev 0, "Surry Unit 1 Modified Replacement CRGT Assembly Reconciliation with MRP-227-A for an 80-Year License", September 2017) listed those Surry Unit 1 replacement CRGT assembly components that were assigned to Categories B and C (i.e., "non-Category A") and did not include the replacement flexures in those categories. Based on this designation as a Category A component, the replacement flexures require no additional measures. Since the flexure design was modified during CRGT replacement, the B&W classification is considered appropriate for the Surry reactor internals program.
7. The fuel alignment pins screen in for multiple mechanisms because of the conservative screening criteria used and the high radiation exposure of the pin locations. However, for the fuel alignment pins in both the upper core plate and the lower core plate, degradation mechanisms other than wear are not expected to impact the function of the pins, either due to the limited amount of degradation anticipated or due to the redundancy of the pins (more than one per fuel assembly). Wear-related surface degradation that has been observed, particularly for pins with Malcomized hardening treatment, is considered the leading degradation mechanism for the fuel alignment pins.

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Table C3.3-4 Comparison: Risk Category Designations from MRP-191, Revision 1, and the Results from the SLR Expert Panel Review

Assembly	Subassembly	Component		Risk Categorization		
				MRP-191, Revision 1 Category	SLR Expert Panel Safety Category	SLR Expert Panel Economic Category
Upper internals assembly	Control rod guide tube assemblies and flow downcomers	Bolts (Note 3)		A	A	A
		C-tubes (Note 3)		C	B	B
		Guide tube enclosures (Note 3)		A	A	A
		Flanges - intermediate (Note 3)		A	A	A
				A	A	A
		Flanges - lower	304 SS	A	B	B
			CF8	B	B	B
		Flexureless inserts (Unit 2 only) (Note 3)		A	A	A
		Flexures (Unit 1 only) (Note 3)		C	C	C
		Guide plates (cards)	304 SS	C	C	C
			CF8	C	C	C
		Guide tube support pins	X-750 (Unit 1)	C	C	C
		Guide tube support pins (Note 3)	316 SS (Unit 2)	A	A	A
		Housing plates (Note 3)	304 SS	A	A	A
			CF8	A	A	A
		Inserts (Unit 1 only) (Note 3)	304 SS	A	A	A
			CF8	--	A	A
		Sheaths (Note 3)		C	C	C
		Support pin nuts	Alloy 600 (Unit 1)	--	Note 1	Note 1
		Support pin nuts (Note 3)	316 SS (Unit 2)	A	A	A
	Mixing devices	Mixing devices (Note 3)		A	A	A
	Upper core plate and fuel alignment pins	Fuel alignment pins		A	B	B
		Upper core plate		B	B	C
		Upper core plate insert (Note 3)		--	B	B
		Upper core plate insert bolts (Note 3)		--	A	A
		Upper core plate insert locking devices and dowel pins (Note 2) (Note 3)		--	A	A
		Upper core plate insert locking devices and dowel pins (Note 2) (Note 3)		--	A	A

Table C3.3-4 Comparison: Risk Category Designations from MRP-191, Revision 1, and the Results from the SLR Expert Panel Review

Assembly	Subassembly	Component		Risk Categorization: MRP-191, Revision 1 Category	Risk Categorization: SLR Expert Panel Safety Category	Risk Categorization: SLR Expert Panel Economic Category
Upper internals assembly (cont.)	Upper instrumentation conduit and supports	Bolting (Note 3)	316 SS	A	A	A
			304SS	A	A	A
		Brackets, clamps, terminal blocks, and conduit straps (Note 3)	304 SS	A	B	C
			CF8	A	A	B
		Conduit seal assembly: body, tubesheets, tubesheet welds (Note 3)		A	B	B
		Conduit seal assembly: tubes (Note 3)		A	B	B
		Conduits (Note 3)		A	A	A
		Flange base (Note 3)		A	A	A
		Locking caps (Note 3)		A	A	A
		Support tubes (Note 3)		A	A	A
	Upper support column assemblies	Adapters (Note 3)		A	A	A
		Bolts (Note 3)		A	A	A
		Column bases (Note 3)		A	A	B
		Column bodies (Note 3)		A	A	B
		Extension tubes (Note 3)		A	A	B
		Flanges (Note 3)		A	A	A
		Lock keys (Note 3)		A	A	A
		Nuts (Note 3)	304 SS	A	A	A
			302 SS	A	A	A
	Upper support plate assembly – flat plate design	Upper support plate (Note 3)		A	A	B
		Upper support ring		B	A	B
		Deep beam ribs (Note 3)		A	A	A
		Deep beam stiffeners (Note 3)		A	A	A
		Bolts (Note 3)		A	A	A
		Locking device (Note 3)		A	A	A

Table C3.3-4 Comparison: Risk Category Designations from MRP-191, Revision 1, and the Results from the SLR Expert Panel Review

Assembly	Subassembly	Component	Risk Categorization		
			MRP-191, Revision 1 Category	SLR Expert Panel Safety Category	SLR Expert Panel Economic Category
Lower internals assembly	Baffle and former assembly	Baffle bolting lock bars (Note 3)	A	B	B
		Baffle-edge bolts	C	B	C
		Baffle plates	B	A	A
		Baffle-former bolts	C	C	C
		Corner bolts	–	C	C
		Barrel-former bolts	C	B	C
		Former plates	B	A	A
	Bottom-mounted instrumentation (BMI) column assemblies	BMI column bodies	B	B	B
		BMI column bolts (Note 3)	A	B	B
		BMI column collars (Note 3)	B	B	B
		BMI column cruciform (Note 3)	B	B	B
		BMI column extension bars (Note 3)	A	A	A
		BMI column extension tubes (Note 3)	B	A	A
		BMI column locking devices (Note 3)	A	A	A
		BMI column nuts (Note 3)	A	A	A
	Core barrel	Core barrel flange (surface)	B	B	B
		Core barrel outlet nozzles	B	B	B
		Lower core barrel axial welds (includes MAW and LAW)	C	B	C
		Lower core barrel girth welds (includes LGW and LFW)	C	B	C
		Upper core barrel axial weld~~s~~ (~~includes~~ UAW)	C	B	C
		Upper core barrel girth welds (includes UFW and UGW)	C	B	C

Table C3.3-4 Comparison: Risk Category Designations from MRP-191, Revision 1, and the Results from the SLR Expert Panel Review

Assembly	Subassembly	Component	Risk Categorization		
			MRP-191, Revision 1 Category	SLR Expert Panel Safety Category	SLR Expert Panel Economic Category
Lower internals assembly	Diffuser plate	Diffuser plate (Note 3)	A	A	A
	Flux thimble (tubes)	Flux thimble tube plugs (Note 3)	B	B	B
		Flux thimbles (tubes)	C	B	B
	Head cooling spray nozzles	Head cooling spray nozzles (Note 3)	A	A	A
	Irradiation specimen guides	Irradiation specimen access plug (dowel pin) (Note 3)	--	A	A
		Irradiation specimen access plug (plug) (Note 3)	A	A	A
		Irradiation specimen access plug (spring) (Note 3)	–	A	A
		Irradiation specimen guide (Note 3)	A	A	A

Table C3.3-4 Comparison: Risk Category Designations from MRP-191, Revision 1, and the Results from the SLR Expert Panel Review

Assembly	Subassembly	Component		Risk Categorization		
				MRP-191, Revision 1 Category	SLR Expert Panel Safety Category	SLR Expert Panel Economic Category
Lower internals assembly (cont.)	Lower core plate and fuel alignment pins	Fuel alignment pins		A	B	B
		Lower core plate		B	A	B
	Lower support column assemblies	Lower support column bodies		B	A	A
		Lower support column bolts		B	B	B
		Lower support column bolt locking devices (Note 3)		–	A	A
		Lower support column nuts (Note 3)		A	A	A
		Lower support column sleeves (Note 3)		A	A	A
	Lower support forging	Lower support forging		A	A	B
	Neutron panels/ thermal shield	Thermal shield bolts (Note 3)		A	B	B
		Thermal shield dowels (Note 3)	316 SS	A	A	A
			304 SS	A	A	A
		Thermal shield flexures		B	B	C
		Thermal shield flexure bolts (Note 3)		–	A	A
		Thermal shield flexure locking devices and dowel pins (Note 3)	304 SS	–	A	A
			304L SS	–	A	A
		Thermal shield (Note 3)		A	A	A
	Radial support keys	Radial support key bolts (Note 3)		A	A	A
		Radial support key dowels (Note 3)	304 SS	–	A	A
			316 SS	–	A	A
		Radial support key lock keys (Note 3)		A	A	A
		Radial support keys	304 SS	A	A	A
			Stellite	–	C	C
	Secondary core support (SCS) assembly	SCS base plate (Note 3)		A	A	A
		SCS bolts (Note 3)		A	A	A
		SCS energy absorber (Note 3)		A	A	A
		SCS guide post (Note 3)		A	A	A
		SCS housing (Note 3)		A	A	A
		SCS lock keys (Note 3)		A	A	A
		Upper and lower tie plates (Note 3)		A	A	A

Table C3.3-4 Comparison: Risk Category Designations from MRP-191, Revision 1, and the Results from the SLR Expert Panel Review

Assembly	Subassembly	Component		Risk Categorization		
				MRP-191, Revision 1 Category	SLR Expert Panel Safety Category	SLR Expert Panel Economic Category
Interfacing components	Interfacing components	Clevis insert bolts		B	B	C
		Clevis insert dowels		–	B	B
		Clevis insert locking devices (Note 3)		A	A	A
		Clevis inserts	Alloy 600	A	A	B
			Stellite	A	C	C
		Head and vessel alignment pin bolts (Note 3)		A	A	A
		Head and vessel alignment pins (Note 3)		A	A	A
		Internals hold-down spring		B	B	C
		Upper core plate alignment pins	304 SS	B	A	A
			Stellite	–	A	B
		Thermal sleeves		–	C	C
		Thermal sleeve guide funnels (Note 3)		–	B	B

Notes:

1 Alloy 600 was identified as the material for the support pin nuts at Surry Unit 1. These nuts were replaced as part of the control rod guide tube support pin replacement performed by AREVA. The AREVA evaluation indicates that the Unit 1 support pin nuts are susceptible to age-related degradation.
2 The upper core plate insert locking devices are 304L SS and the dowel pins are 316 SS.
3 No additional measures

C4 PRIMARY, EXPANSION, OR EXISTING PROGRAMS INSPECTION REQUIREMENTS

Individual tables are provided to list the PWR vessel internals components which will require inspection for SLR. Each of these tables include applicable aging effects to be managed, the examination methods, and the examination coverage. Table C4.3-1 lists the Primary components to be examined. Table C4.3-2 includes the Expansion components. Table C4.3-3 lists the components which have Existing examinations.

C4.1 CHANGES TO THE CURRENT PRIMARY, EXPANSION, OR EXISTING PROGRAMS INSPECTION REQUIREMENTS

Seven components or component groups that are currently Primary, Expansion, or Existing inspections items in MRP-227, Revision 1, are expected to require changes for MRP-227, Revision 2:

Changes due to SLR expert panel review

- Baffle-former bolts (clarification for corner bolts)
- Baffle-edge bolts (clarification for bracket bolts, but bracket bolts are not applicable for the Surry units)

Potential changes due to NRC RAIs for MRP-227, Revision 1, or due to Interim Guidance

- Upper core plate
- Baffle-former bolts
- Baffle-former bolt expansion criteria
- Core barrel welds
- Lower support columns
- Lower support forging

Changes due to SLR expert panel review

- Baffle-former bolts

The SLR expert panel review added the corner bolts components under the baffle and former assembly. These bolts were not missed during the development of MRP-191, Revision 1 or MRP-227, Revision 1. In those documents, the corner bolts were assumed to be included under the baffle-former bolts since they were located in similar locations and performed similar functions. For the development of MRP-227, Revision 2, the SLR expert panel decided that additional clarity should be added by including the corner bolts by name.

All of the screening, categorization, and ranking conclusion for the baffle-former bolts are also applicable to the corner bolts.

Potential changes due to NRC RAIs for MRP-227, Revision 1, or due to Interim Guidance

- Upper core plate

  NRC RAI 14 for MRP-227, Revision 1 has questioned the reduction in inspection coverage and inspection technique from MRP-227-A to MRP-227, Revision 1 for the upper core plate. This could result in changes to the requirements of MRP-227, Revision 1, in an NRC-approved version.

- Baffle-former bolts

  As a response to the operating experience with baffle-former bolts, the industry developed MRP-2017-009, "Transmittal of NEI 03-08 'Needed' Interim Guidance Baffle Former Bolt Inspections for PWR Plants as Defined in Westinghouse NSAL 16-01 Rev. 1" that modified the initial inspection timing, evaluation criteria, and re-inspection interval for the bolts. The NRC staff assessed the technical basis behind the interim guidance and accepted the guidance for aging management of baffle-former bolts (Reference ML17310A861). NRC RAI 8 also asked a question about how the industry plans to respond to the baffle-former bolt experience, and the response was that the baffle-former bolt interim guidance MRP-2017-009 would be used.

- Baffle-former bolt Expansion criteria

  MRP-2018-002, ""Transmittal of NEI 03-08 'Needed' Interim Guidance Regarding MRP-227-A and MRP-227, Revision 1 Baffle-Former Bolt Expansion Inspection Requirements for PWR Plants" on the baffle-former bolt Expansion criteria was published to address cases where large clusters of degraded bolts of bolts with relevant indications were observed. MRP-2018-002 defined what is considered a large cluster of degraded bolts and provided a revised Expansion inspection requirement to visually inspect at least a portion of the barrel-former bolts if a large cluster of degraded baffle-former bolts is observed. Item 3.b of MRP 2018-002 provides the following information:

  (a) 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 visual (VT-3) inspection 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 last 4 rows high by at last 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.

(b) 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.

- Core barrel welds

  The response to RAI 5 provided a basis for reduced inspection coverage of the core barrel welds, and RAI 26 provided a basis for the assignment of welds to the Primary or Expansion component lists. MRP 2018-026 provides an update of the required inspections for the core barrel upper flange weld (UFW), upper girth weld (UGW), lower girth weld (LGW), lower flange weld (LFW), upper axial weld (UAW), middle axial weld (MAW), and lower axial weld (LAW) include additional examination coverage.

- Lower support columns

  The response to RAI 9 provided a basis for the reduced (25%) inspection coverage and VT-3 examinations for the lower support columns. These changes were implemented in MRP-227, Revision 1, and were included in MRP 2018-022.

- Lower support forging

  The response to RAI 14 provided a basis for the reduced (25%) inspection coverage and VT-3 examination for the lower support forging. These changes were implemented in MRP-227, Revision 1, and were included in MRP 2018-022.

C4.2 ADDITIONAL COMPONENTS TO BE ADDED TO THE PRIMARY, EXPANSION, OR EXISTING PROGRAMS CATEGORIES

It is expected that five components or component groups will be added to the Westinghouse Primary, Expansion, or Existing component categories in MRP-227, Revision 1:

- Primary
  - Clevis insert bolts and dowels (elevated from Existing)
  - Thermal sleeves
  - Core barrel assembly radial support keys
  - Clevis inserts (elevated from Existing)
- Expansion
  - None
- Existing
  - Malcomized fuel alignment pins

Clevis Insert Bolts and Dowels

The experience in Westinghouse plants with clevis insert bolt cracking and clevis insert dowel degradation indicates that the clevis insert bolts and dowels need to be managed for potential aging degradation. The cracking of bolts was due to susceptibility of the Alloy X-750 bolts to primary water SCC. The degradation of the dowels was likely related to the same aging degradation mechanism. Based on the operating experience to date and the high susceptibility of this material, the SLR expert panel assigned the clevis bolts to safety risk Category B and economic risk Category C. The SLR expert panel also added the clevis insert dowels as a separate line item in MRP-191, and assigned the dowels to safety risk Category B.

The clevis insert bolts were included in both MRP-227-A and MRP-227, Revision 1, as an Existing inspection item. Due to the fact that degradation of the clevis insert bolts has been observed at multiple plants, the bolts have been elevated from Existing to Primary for MRP 2018-022. This elevation also is supported by the fact that no other component in the Westinghouse reactor vessel internals could effectively serve as a leading indicator for the primary water SCC that clevis insert bolts are expected to experience. Some degradation has been observed in the clevis insert bolts prior to the first PEO at 40 years. The re-inspection interval would be 10 years.

The general visual inspection (VT-3) of ASME Code Section XI that was specified for the clevis insert bolts may detect degradation of the bolts, but if the degradation is hidden beneath the head, it may not. Past inspection experience has shown that once bolts are fully separated and the heads have begun to wear on locking devices or the clevis insert, the VT-3 examination can detect degradation. Evaluation of clevis insert bolt cracking (PWROG-15034-P) has determined that degraded clevis insert bolts would not result in a loss of function of the lower radial support system, and thus should not pose a safety concern. Several physical constraints were shown to prevent this loss of function during operation. This technical basis supported the conclusion that the current general visual (VT-3) examinations from MRP-227 are sufficient to manage the safety function of the lower radial support system. Proactive replacement of these bolts would be an acceptable approach to manage the potential degradation.

The clevis insert dowels were not included in MRP-227, Revision 1, as a Primary, Expansion, or Existing Programs inspection component. Since degradation has already been observed in the dowels, they have been elevated in MRP 2018-022. The dowels are located directly adjacent to the clevis insert bolts, and the expected degradation (fractured tack welds on the dowels or rotation of the dowels) can be detected by the same general visual (VT-3) inspection specified for bolts. Thus, these two components are combined into the same Primary inspection requirement. Typically, the safety risk Category B assignment of the clevis insert bolts and dowels would not automatically result in the bolts being assigned a Primary inspection. However, multiple instances of active degradation and the potential for varying Existing component inspection requirements from plant-to-plant merit a more conservative aging management approach.

The degradation mechanism is equally likely to occur at any clevis insert bolt or dowel location, so the required coverage should be 100% of the accessible clevis insert bolts and dowels. All of the bolts and dowels are expected to be accessible.

Thermal sleeves

Wear of the reactor vessel head adapter thermal sleeve has been observed at several Westinghouse-designed plants. This has reached unacceptable levels in some cases and resulted in thermal sleeves breaking free from their normal position. The wear occurs in three locations: the thermal sleeve flange, the outer diameter of the sleeve, and the inner diameter of the sleeve.

Based on this operating experience and the potential for significant nuclear safety consequences and economic consequences, the SLR expert panel review concluded that these thermal sleeves have been assigned to both safety and economic risk Category C. Recent operating experience indicates that wear of the thermal sleeves scan impede the ability to insert a control rod assembly (NSAL-18-1, Thermal Sleeve Flange Wear Leads to Stuck Control Rod). This potential safety impact would increase the safety consequence and likely increase the safety risk category. For the purposes of the interim guidance, the safety risk category is raised to C.

No other component in the reactor vessel internals can provide a leading indication for the wear degradation that has been observed in the thermal sleeves, and the wear to date has resulted in failures. Based on these reasons and the potential impacts on safety, the thermal sleeves are assigned as Primary inspection components by MRP 2018-022.

Some aspects of the wear degradation in the thermal sleeves can be detected with a general visual examination, but much of the wear occurs in locations that are inaccessible to a visual inspection or in a manner which obscures effective visual detection of the wear. Therefore, the following techniques are recommended for detecting wear of the thermal sleeves:

- Ultrasonic test (UT) to detect inner diameter or outer diameter wear of the sleeves.
- Measurements of the height of the thermal sleeve funnels relative to the reactor vessel closure head to detect wear in the thermal sleeve flange.

The inspection should be conducted per the plant design-specific inspection recommendations in TB 07-02. The inspection recommendations include the type, coverage, and timing of the inspection. The inspection is identified in MRP 2018-027 as a NEI 03-08 Needed Inspection.

Wear Surfaces of the Radial Support Keys and Clevis Inserts

Wear on the Stellite hardfacing surfaces of the radial support keys and clevis inserts is a concern for the Westinghouse-design plants. These are mating components that provide alignment for the core barrel. This wear could particularly become an issue as plants continue operation into the second PEO. The SLR expert panel determined that the wear of the clevis inserts and radial support keys should be elevated to Category C for both safety and economics. The elevated safety concern was due to the fact that these provide a core support and safe shutdown function by limiting the amount of circumferential or radial displacement in the core barrel. The elevated economic concern stemmed from the high difficulty of repairing these components due to the precision fits that were required during the original fabrication. The same reasoning was deemed applicable to both components.

The clevis inserts were not included in MRP-227-A, but are included in MRP-227, Revision 1, as an existing inspection component. Based on the results of the expert panel review, the clevis inserts have been elevated to be a Primary inspection component. The radial support keys were not assigned to an inspection category in either MRP-227-A or MRP-227, Revision 1, and should also be added to the Primary inspection category based on the expert panel review results. Operating experience has shown that significant wear is already occurring on these components at some plants, and logically, this wear will continue to increase into the second PEO.

All locations are potentially susceptible to wear on these components, so the coverage requirement should be 100% of the radial support keys and 100% of the clevis inserts. The inspection must focus on the wear surfaces and look for evidence of excessive wear. The inspection type will be general visual (VT-3). Note that this inspection is intended to detect the presence of wear on these surfaces, but is not expected to be effective at measuring the full extent of material loss that may have occurred. Such measurements are beyond the scope of this existing inspection, but may be required for evaluation and disposition of a relevant condition. The re-inspection interval would be 10 years.

Malcomized Fuel Alignment Pins

Per Westinghouse Technical Bulletin TB-16-4, accelerated loss of material degradation has been observed on fuel alignment pins that have a malcomized surface. This was a surface commonly used at many early plants to increase the hardness and resistance to wear. The degradation appears as a thin layer of material flaking off of the surface. The fuel alignment pins on both the upper core plate and the lower core plate can be affected by this mechanism, if they are malcomized. Based on the known operating experience, the SLR expert panel assigned these fuel alignment pins to a high likelihood of degradation, but maintained a low safety consequence because of the evaluations documented in TB-16-4. The evaluations showed that the loss of the malcomized surface layer and the resulting larger gap between the fuel assemblies and the fuel alignment pins should have a small effect on fuel mechanical and reload design criteria, and on loss of coolant accident analyses. Thus the expert panel review assigned the malcomized fuel alignment pins to safety Category B.

The fuel alignment pins are inspected regularly under existing ASME Code Section XI requirements. This inspection is a general visual (VT-3) and is appropriate for detection of the loss of material that may occur. Coverage should be 100% of the accessible fuel alignment pins, since the degradation can occur on any of the malcomized locations. The re-inspection interval would be 10 years.

C4.3 COMPONENT DESIGNATIONS FOR PRIMARY, EXPANSION, OR EXISTING PROGRAMS INSPECTIONS

Aging management requirements for Primary, Expansion, and Existing Components are covered in the Tables noted below. A brief description of changes incorporated since the issue of MRP-227-A and source of changes are identified in the column titled "Source of Revision/Addition."

Table C4.3-1, Primary Components

Table C4.3-2, Expansion Components

Table C4.3-3, Existing Programs Components

Table C4.3-1 Primary Components

Primary Item	Effect (mechanism)	Expansion Link (Note 1)	Examination Method / Frequency (Note 1)	Examination Coverage	Source of Revision/ Addition
Control Rod Guide Tube Assembly Guide plates (cards)	Loss of material (wear)	Control rod guide tube continuous section sheaths and C-tubes (Note ~~18~~15)	Visual (VT-3) inspections and quantitative measurements are performed. Per the requirements of WCAP-17451-P, the absence of significant degradation during the inspections in 2012, confirm that no additional inspection is required prior to the normal ten-year interval[a] (Note 2).	An update provided in MRP 2018-007 indicates wear measurements to be obtained in 37 of the 48 CRGT locations.	MRP-227, Rev. 1 added WCAP-17451-P, MRP-2018-007 supplements industry WCAP-17451-P requirements.
Control Rod Guide Tube Assembly Lower flange welds, LFW	Cracking (SCC, Fatigue) Irradiation Embrittlement (IE) and Thermal Embrittlement (TE) are applicable aging mechanisms	Remaining accessible CRGT assembly lower flange welds BMI column bodies (Note 3)	Enhanced visual (EVT-1) examination to determine the presence of crack-like surface flaws in flange welds no later than 2 refueling outages from the beginning of the first license renewal period and subsequent examination on a ten-year interval.[b]	100% of outer (accessible) CRGT lower flange weld surfaces and 0.25-inch of the adjacent base metal on the individual periphery CRGT assemblies (Notes 4 and 5).	Rev. 1 added Expansion to remaining CRGT lower flange welds; Rev. 1 removed Expansion to items upper core plate and lower support forging; added 0.25 inch of base metal to examination coverage.
Core Barrel Assembly Upper flange weld; UFW	Cracking (SCC)	Upper girth weld (UGW) Lower flange weld (LFW) Upper axial weld (UAW) Lower support forging. (Note 3)	Enhanced visual (EVT-1) examination, no later than 2 refueling outages from the beginning of the first license renewal period and subsequent examination on a ten-year interval.[c]	100% of the accessible weld length of one side of the UFW and 0.75-inch of adjacent base metal shall be examined. (Notes 6 and 9).	MRP-227A initially established examination coverage. MRP-227, Rev 1, removed Expansion to core barrel outlet nozzles, and to lower support column bodies; Rev. 1 added Expansion to UGW, LFW, and UAW, and to lower support forging/casting; reduced coverage to 50% of the length for either ID or OD of the weld being examined.~~25%.~~ ~~However~~ MRP 2018-026 ~~increased the~~ also ~~required~~requires ~~-~~a minimum of 50%examination coverage.

Table C4.3-1 Primary Components

Primary Item	Effect (mechanism)	Expansion Link (Note 1)	Examination Method / Frequency (Note 1)	Examination Coverage	Source of Revision/ Addition
Core Barrel Assembly Lower girth weld; LGW (Note 8)	Cracking (SCC, IASCC, Fatigue) Irradiation Embrittlement (IE) is an applicable aging mechanism.	Middle and lower core barrel axial welds. Upper core plate. Lower support column bodies (cast). (Note 3)	Periodic enhanced visual (EVT-1) examination, no later than 2 refueling outages from the beginning of the first license renewal period and subsequent examinations on a ten-year interval.[d]	100% of the accessible weld length of the OD of the LGW and 0.75-inch of adjacent base metal shall be examined. (Note 9).	MRP 2018-022 added core barrel axial welds, upper core plate, and lower support column bodies as Expansion items. MRP 2018-026 revised the required examination coverage to be a minimum of 50%. Confirmed in MRP-227, Rev. 1.
			One time enhanced visual (EVT-1) examination of the core barrel middle axial weld (MAW) and lower axial weld (LAW) during the sixth inservice inspection interval (i.e., a "50-year inspection") no later than six months prior to the subsequent period of extended operation (SPEO).	100% of the accessible weld lengths from the barrel outer diameter for the MAW and the LAW and 3/4-inch of base metal on each side of the weld AND a vertical zone on each side of the inaccessible portion of the barrel containing the known location of the axial weld; each zone should be a minimum of 3/4-inch wide and cover the full distance parallel to the inaccessible height of the weld.	MRP 2019-009, Table 2, Row 3 (Axial weld locations are known but partially inaccessible)
Core Barrel Assembly Lower core barrel flange weld. (Note~~s~~ 10 ~~and 11~~)	Cracking (SCC, Fatigue)	None	Periodic enhanced visual (EVT-1) examination, no later than 2 refueling outages from the beginning of the first license renewal period and subsequent examinations on a ten-year interval.[e]	100% of one side of the accessible surfaces of the selected weld and adjacent base metal ~~(Notes 6 and 7)~~.	
Baffle-Former Assembly Baffle-edge bolts (Note ~~12~~11)	Cracking (IASCC, Fatigue) that results in • Lost or broken locking devices • Failed or missing bolts • Protrusion of bolt heads Irradiation embrittlement (IE) and irradiation-enhanced stress relaxation (ISR) are applicable aging mechanisms. (Note ~~15~~14)	None	Visual (VT-3) examination, with baseline examination between 20 and 40 EFPY and subsequent examinations on a ten-year interval.[f]	Bolts and locking devices on high fluence seams. 100% of components accessible from core side. ~~(Note 13)~~	MRP-227A. (confirmed in MRP-227, Rev. 1). SPS does not have bracket bolts.

Table C4.3-1 Primary Components

Primary Item	Effect (mechanism)	Expansion Link (Note 1)	Examination Method / Frequency (Note 1)	Examination Coverage	Source of Revision/ Addition
Baffle-Former Assembly Baffle-former bolts Corner bolts. (Note ~~11~~13)	Cracking (IASCC, Fatigue) Irradiation embrittlement (IE) and Irradiation-enhanced stress relaxation (ISR) are applicable aging mechanisms. (Note ~~15~~14)	Lower support column bolts, Barrel-former bolts	Since Surry is a Tier 2b plant per NSAL-16-1, letter MRP 2017-009 requires that baseline volumetric (UT) examination be performed no later 30 EFPY. Since the Surry units have <3% indications with no clustering (per MRP 2017-009), subsequent UT examinations[g] are on a ten-year interval.[h] ~~(Note 16)~~	100% of accessible bolts. (Note 12) Heads accessible from the core side. UT accessibility may be affected by complexity of head and locking device designs. (Note 17)	MRP-227, Rev.1, includes generic information based on MRP 2017-009. Appendix C provides the plant-specific information for Surry based on MRP 2017-009. MRP-227, Rev. 1 added Note 9 to include corner bolts. MRP 2018-022 clarified by identifying corner bolts as component.
Baffle-Former Assembly Assembly (includes: baffle plates, baffle edge bolts, and indirect effects of assembly void swelling in former plates)	Distortion (void swelling), or Cracking (IASCC) that results in: • Abnormal interaction with fuel assemblies • Gaps along high fluence baffle joints • Vertical displacement of baffle plate near high fluence joints • Broken or damaged edge bolts, locking systems along high fluence baffle joints	None	Visual (VT-3) examination to check for evidence of distortion, with baseline examination between 20 and 40 EFPY and subsequent examinations on a ten-year interval.[i]	Core side surface: ~~as indicated by MRP 227-A Figures 4-24, 4-25, 4-26, and 4-27.~~ • high fluence baffle joints • Top and bottom edges of baffle plates • bolts and locking devices	MRP-227, Rev. 1 clarifies extent of Examination Coverage
Alignment and Interfacing Components Internals hold down spring	Distortion (Loss of load due to stress relaxation) ~~(Note 17)~~	None	Direct measurement of spring height within three cycles of the beginning of (before or after) the first license renewal period. If the first set of measurements is not sufficient to assess remaining life, additional spring height measurements will be required.[j] ~~(Note 17)~~	Measurements should be taken at several points around the circumference of the spring, with a statistically adequate number of measurements at each point to minimize uncertainty.	MRP-227A. (confirmed in MRP-227, Rev. 1). A calculation of required hold down spring height for the 80-year design life confirms that the existing measured spring heights for both units are acceptable, and no further measurements are necessary
Alignment and Interfacing Components Clevis insert bolts Clevis insert dowels (Note ~~19~~16)	Cracking (SCC), Loss of material (Wear)	None	Visual (VT-3) no later than 2 refueling outages from the beginning of the first license renewal period. [k] Subsequent examinations on a ten-year interval.	All clevis insert bolts and clevis insert dowels.	Clevis insert bolts elevated to the Primary category by MRP 2018-022; the scope is expanded to include clevis insert dowels.

Table C4.3-1 Primary Components

Primary Item	Effect (mechanism)	Expansion Link (Note 1)	Examination Method / Frequency (Note 1)	Examination Coverage	Source of Revision/ Addition
Alignment and Interfacing Components Thermal sleeves (Note 16)	Loss of material (Wear)	None	Visual inspection for top of CRGTs and/or bottom of thermal sleeve guide funnel for indications of wear per MRP 2018-010 (TB-07-02). MRP 2018-027 implements this inspection as described in NSAL 18-1.	Wear surfaces for top of CRGT and/or bottom of thermal sleeve guide funnel per MRP 2018-010 (TB-07-02).	Added as a Primary component in MRP 2018-022.
Thermal Shield Assembly Thermal shield flexures	Cracking (fatigue) or Loss of Material (wear) that results in thermal shield flexures excessive wear, fracture, or full separation	None	Visual (VT-3) no later than 2 refueling outages from the beginning of the first license renewal period. Subsequent examinations on a ten-year interval.[l]	100% of thermal shield flexures	MRP-227A (confirmed in MRP-227, Rev. 1).
Radial Support Keys Radial support keys Stellite wear surfaces (Note ~~19~~16)	Loss of material (Wear)	None	Visual (VT-3) no later than 2 refueling outages from the beginning of the first license renewal period. Subsequent examinations on a ten-year interval.	Wear surfaces and radial support keys	Added as a Primary component in MRP 2018-022.
Alignment and Interfacing Components Clevis bearing Stellite wear surface (Note ~~19~~16)	Loss of material (Wear)	None	Visual (VT-3) no later than 2 refueling outages from the beginning of the first license renewal period. Subsequent examinations on a ten-year interval.	Wear surfaces and radial support keys	Added as a Primary component in MRP 2018-022.

a. During refueling outages in 2012, control rod guide tube (CRGT) assembly guide card VT-3 inspections were performed for Surry Units 1 and 2. The CRGT assemblies had been replaced in Unit 1 in the mid 1980's; the CRGT assemblies for Unit 2 were the original components. 20% of the CRGT assemblies were inspected for each unit. The criteria of WCAP-17451-P were not applicable in 2012. However, the results obtained in 2012 confirm that no unacceptable values of guide card wear were found, and the designated criterion zone for both units is the "green zone". The nominal guide card slot width for the 15x15 fuel used at Surry is 0.277 inch. The maximum measured values for the slot widths on the 80 guide cards inspected for Unit 1 was 0.2851 inch; the Unit 2 maximum was 0.2850 inch. The other parameter monitored for guide cards is the ligament length, and the nominal value is 0.1859 inch. The minimum value of ligament length was 0.165 inch for both units. These differences of 11%, or less, between nominal values and measured values indicate no concern for guide card wear. The subsequent inspection period typically would be set based on a predictive wear calculation. Considering the small amount of wear, no additional inspection is required prior to the planned 10-year re-inspection. Also, control rod drop times are trended relative to technical specification limits as an additional indicator for possible guide card degradation.

b. EVT-1 inspections performed in 2012 for Surry Units 1 and 2 found no unacceptable results for the lower flange welds during the 24 control rod guide tube assembly inspections that were performed for each unit.

c. In 2012, the upper core barrel flange welds were inspected using EVT-1 for both units. The weld examinations yielded acceptable results for both units.

d. 70.4% of the lower girth (circumferential) weld was inspected using EVT-1 in 2013 on Unit 1. When combined with the inspection of the upper girth weld, a total of 85% of the welds was examined. 71.6% of the lower girth weld was inspected in 2014 on Unit 2. When combined with the inspection of the upper girth weld, a total of 85.6% of the welds was examined. No unacceptable inspection results were found for either unit.

e. The lower core barrel flange weld was inspected in 2013 for Unit 1, and in 2014 for Unit 2. The inspection was performed from the exterior of the core barrel. Cleaning of the weld was not required. 82% of the weld circumference was inspected for Unit 1; 81.5% of the circumference was inspected for Unit 2. Coverage limitations occurred due to the narrow gap between the core barrel and the reactor cavity wall. No issues were identified.

f. Baffle-edge bolt VT-3 examinations were performed in 2010 for Unit 1 and in 2011 for Unit 2 (approximately 28 EFPY for each unit). 936 accessible edge bolts were inspected for each unit. The only Unit 1 degradation that was noted for baffle-edge bolts was a missing weld on one end of the locking bar on one bolt which was determined to be an original fabrication condition. No further action was recommended. For Unit 2, no degradation of baffle edge bolts was noted.

g. MRP 2017-009 allows, as an alternative for performing UT inspections, a proactive effort for bolting replacements, or a plant-specific evaluation using established methodologies (e.g., WCAP-15029-P-A or equivalent).

h. VT-3 and UT examinations of baffle-former bolts were performed in 2010 for Unit 1 (approximately 28 EFPY per 1-PT-4) and in 2011 for Unit 2 (approximately 28 EFPY per 2-PT-4). The entire population of 1088 bolts was inspected for both units. Surry Units 1 and 2 are designated Tier 2. For Unit 1, there were four findings. There were two bolts that were non-inspectable using UT due to deformation at the points on the hex heads that affected the back wall signal. However, reviews of the UT signals concluded no flaws. Those bolts were verified to be acceptable per VT-3 results. Most of the VT-3 inspection results were satisfactory. One bolt had unacceptable VT-3 results due to a missing locking bar weld on one end, but that was evaluated to be an original fabrication condition, and no further action was recommended. The UT result was satisfactory. One bolt was rejectable for UT results due to a flaw in the head-to-shank region, but had an acceptable VT-3 result. Corrective action recommended a VT-3 examination every other refueling outage to visually verify that the two welds on the baffle-bolt locking bar are intact with no visible signs of degradation.
For Unit 2, all VT-3 results were acceptable, but there were two reportable indications from the UT examinations. The visual examination for those two bolts showed no structural damage to the bolt head, locking bar or locking bar welds. The two indications were bounded by existing analysis which confirmed structural integrity and safety function of the reactor internals assembly.

i. VT-3 examinations were performed in 2013 for Unit 1 and in 2014 for Unit 2 (approximately 31 EFPY for each unit). Inspections of baffle plates, as an indication for indirect effects of void swelling, found no vertical displacement of the baffle plates. The baffle plates were vertical, and there was no evidence of warping or misalignment along the baffle seams. These findings are applicable for both units.

j. Direct measurements of the hold down spring height were performed for Unit 1 and Unit 2 in 2012. The measurements were obtained at 8 locations around the circumference of the spring. Three measurements were performed at each location. The results indicated an acceptable spring height that confirms the capability of the hold down spring to perform its intended function for 80 years of operation.

k. The clevis insert bolting was inspected for integrity during the 2013 and 2014 outages for Unit 1 and Unit 2, respectively. VT-3 exams were performed using VT-1 acuity. The enhanced visual acuity was used specifically to address industry OE concerns of clevis insert bolt cracking. No issues were identified.

l. VT-3 examinations were performed in 2013 for the six thermal shield flexures in Unit 1. The Unit 2 inspections for the six thermal shield flexures were performed in 2014. All inspection results were satisfactory; there was no evidence of cracking (fatigue) or loss of material (wear).

Notes:

1 Examination acceptance criteria and expansion criteria for the Westinghouse components are in Table 5-3 of MRP-227~~-A~~, Revision 1.

2 Examination method updated in MRP-227, Revision 1 based on issuance of WCAP-17451-P for industry use. ~~Interim Guidance issued in PWROG Letter OG-18-76 amends the requirements regarding baseline examinations.~~

3 The FMECA expert panel determined that Surry would follow MRP-227, Revision 1, for the expansion inspection components of the CRGT lower flange welds, which include the remaining CRGT lower flange welds and the BMI column bodies. The lower support columns (cast) and the upper core plate are

added as Expansion links to the lower core barrel girth weld (Primary), and the lower core support forging would be added as an Expansion link to the upper core barrel flange weld (Primary).

4 ~~MRP-227-A Note:~~ A minimum of 75% of the total identified sample population must be examined.

5 Clarification in MRP-227, Revision 1, ~~to~~ stated that 0.25 inch of the adjacent base metal must be examined for the CRGT lower flange welds.

6 ~~MRP-227-A Note:~~ A minimum of 75% of the total weld length (examined + unexamined), including coverage consistent with the Expansion criteria in Table 5-3, must be examined from either the inner or outer diameter for inspection credit.

7 The examination coverage for core barrel welds was redefined in MRP-227, Revision 1.

8 The upper girth weld was moved to an Expansion link from the upper flange weld in MRP-227, Revision 1.

9 MRP 2018-026 (and MRP-227, Revision 1) revised the examination coverage to require a minimum of 50% of the circumference of either the ID or the OD of the weld being examined

10 ~~MRP-227-A Note: The lower core barrel flange weld may be alternatively designated as the core barrel-to-support plate weld.~~

11 The core barrel lower flange weld was moved to an Expansion link from the upper flange weld in MRP-227, Revision 1.

12 Bracket bolts are not applicable to the Surry design.

13 ~~MRP-227-A Note:~~ A minimum of 75% of the total bolt population (examine + unexamined), including coverage consistent with the Expansion criteria in Table 5-3 of MRP-227, must be examined for inspection credit.

14 Baffle-former bolt inspections include inspections of the corner plate bolts when applicable.

15 ~~Corner bolts will be added as a Primary component in the next revision of MRP-227. They will be treated the same as baffle-former bolts.~~

16 ~~MRP-227-A Note:~~ Void swelling effects on the component are managed through management of void swelling on the entire baffle-former assembly.

17 ~~Examination timing and frequency is updated in MRP-227, Revision 1, based in issuance of MRP-2017-009 for industry use.~~

18 ~~Language clarified/simplified in MRP-227, Revision 1.~~

19 Sheath or C-tube wear measurement can be considered best practice, but optional until the inspection when the guide card wear just above the sheaths or C-tubes has a ligament that is worn-through or is projected to wear-through before the time of the next inspection.

20 Added as a Primary component in MRP 2018-022.

21 MRP 2018-002 describes clustering of indications for baffle-former bolting that would necessitate additional inspections. Item 3.b of MRP 2018-002 provides the following information regarding the expansion criteria for those additional inspections:

(a) 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 visual (VT-3) inspection 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 last 4 rows high by at last 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.

(b) 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.

Table C4.3-2 Expansion Components

Expansion Item	Effect (mechanism)	Primary Link (Note 1)	Examination Method / Frequency	Examination Coverage	Source of Revision/ Addition
Upper Internals Assembly Upper core plate	Cracking (Fatigue, wear)	Core barrel Lower Girth Weld (Note 2)	Visual (VT-3) examination. Re-inspection every 10 years following initial inspection. (Note 3)	25% of accessible surfaces. (Notes 4 and 5)	MRP-227, Revision 1. MRP 2018-022 specified VT-3 examination and 25% coverage.
Control Rod Guide Tube Assembly Remaining CRGT lower flange welds (Note 6)	Cracking (SCC, Fatigue) Irradiation Embrittlement (IE) and Thermal Embrittlement (TE) are applicable aging mechanisms.	CRGT Lower Flange Welds (Notes 2 and 6)	Enhanced visual (EVT-1) examination to determine the presence of crack-like surface flaws in flange welds. Subsequent examination on a ten-year interval.	A minimum of 75% of the CRGT assembly lower flange weld surfaces and 0.25 inch of the adjacent base metal for the flange welds not inspected under the Primary link.	MRP-227, Revision 1, added the requirement for 0.25 inch of adjacent base metal.
Control Rod Guide Tube Assembly Continuous section sheaths and C-tubes	Loss of Material (Wear)	CRGT Guide Plates (cards)	Per the requirements of WCAP-17451-P, Revision 2.	Examination coverage per the requirements of WCAP-17451-P, Revision 2	MRP-227A (and MRP-227, Rev. 1) lists these iitems as "No Additional Measures," but WCAP-17451 elevated these items to Expansion.
Bottom Mounted Instrumentation System Bottom-mounted instrumentation (BMI) column bodies	Cracking (Fatigue) including the detection of completely fractured column bodies. Irradiation Embrittlement (IE) is an applicable aging mechanism.	CRGT Lower Flange Welds (Note 2)	Visual (VT-3) examination ~~of BMI column bodies as indicated by difficulty of insertion / withdrawal of flux thimbles.~~ Re-inspection every 10 years following initial inspection. ~~Flux thimble insertion / withdrawal to be monitored at each inspection interval.~~	100% of BMI column bodies for which difficulty is detected during flux thimble insertion/withdrawal.	MRP-227A, (confirmed in MRP-227, Rev. 1)
Core Barrel Assembly Middle axial weld (MAW) and Lower axial weld (LAW)	Cracking (SCC, IASCC) Irradiation Embrittlement (IE) is the applicable aging mechanism.	Lower core barrel cylinder girth weld (LGW)	Enhanced visual (EVT-1) examination. Re-inspection every 10 years following initial inspection.[a]	100% of the accessible weld length of the OD of the MAW and LAW and 0.75-inch of adjacent base metal shall be examined. (Note~~s 4 and~~ 10~~8~~)	MRP 2018-026 changed the examination coverage.

Table C4.3-2 Expansion Components

Expansion Item	Effect (mechanism)	Primary Link (Note 1)	Examination Method / Frequency	Examination Coverage	Source of Revision/ Addition
Core Barrel Assembly Upper girth weld (UGW)	Cracking (SCC)	Upper core barrel flange weld (UFW).	Enhanced visual (EVT-1) examination. Re-inspection every 10 years following initial inspection.[b]	100% of the accessible weld length of one side of the UGW and 0.75-inch of adjacent base metal shall be examined (Notes 8 and 9)	MRP-227, Revision 1, added the UGW to the Expansion category as a link from Primary-Upper flange weld (UFW). MRP 2018-026 changed the examination coverage.
Core Barrel Assembly Lower flange weld (LFW)	Cracking (SCC)	Upper core barrel flange weld (UFW).	Enhanced visual (EVT-1) examination. Re-inspection every 10 years following initial inspection.[c]	100% of the accessible weld length of the OD surface of the LFW and 0.75-inch of adjacent base metal shall be examined. (Note 8)	MRP-227, Revision 1, added the LFW to the Expansion category as a link from Primary-Upper flange weld (UFW). MRP 2018-026 changed the examination coverage.
Core Barrel Assembly Upper axial weld (UAW)	Cracking (SCC, IASCC) Irradiation Embrittlement (IE) is an applicable aging mechanism.	Upper core barrel flange weld (UFW).	Enhanced visual (EVT-1) examination. Re-inspection every 10 years following initial inspection.[d]	100% of the accessible weld length of one side of the UAW and ¾' of adjacent base metal shall be examined (Note 8)	MRP-227, Revision 1, added the UAW to the Expansion category as a link from Primary-Upper flange weld (UFW). MRP 2018-026 changed the examination coverage.
Lower Internals Assembly Lower support forging	Cracking (SCC)	Upper Core Barrel Flange Weld (UFW) (Note 2)	Visual (VT-3) examination. Re-inspection every 10 years following initial inspection. (Note 3)	25% of the bottom surface. (Notes 4 and 5)	MRP-227, Revision 1, added this item to the Expansion category. MRP 2018-022 specified VT-3 examination and 25% coverage.

Table C4.3-2 Expansion Components

Expansion Item	Effect (mechanism)	Primary Link (Note 1)	Examination Method / Frequency	Examination Coverage	Source of Revision/ Addition
Lower Support Assembly Lower support column bodies (cast)	Cracking (IASCC) including detection of completely fractured column bodies. Irradiation Embrittlement (IE) is an applicable aging mechanism.	Lower core barrel girth Weld (Note 2)	Visual (VT-3) examination. Re-inspection every 10 years following initial inspection. (Note 3)	25% of ~~accessible support~~ the total number of column assemblies (both visible and non-visible from the lower core plate) using a VT-3 examination ~~as visible~~ from above the lower core plate. The inspection coverage must be evenly distributed across the population of column assemblies (Notes 4 and ~~5~~11)	MRP-227, Revision 1, added this item to the Expansion category. MRP 2018-022 specified VT-3 examination and 25% coverage. (confirmed in MRP-227, Rev. 1)
Core Barrel Assembly Barrel-former bolts (Note 7)	Cracking (IASCC, Fatigue) Irradiation Embrittlement (IE), void swelling, irradiation-enhanced stress relaxation (ISR) aging mechanisms	Baffle-former bolts	Volumetric (UT) examination Re-inspection every 10 years following initial inspection.	100% of accessible barrel-former bolts (minimum of 75% of the total population). Accessibility may be limited by presence of thermal shield or neutron pads. (Note 4)	MRP-227A (confirmed in MRP-227, Rev. 1)
Lower Support Assembly Lower support column bolts	Cracking (IASCC, Fatigue) Irradiation embrittlement (IE), and irradiation-enhanced stress relaxation (ISR) are applicable aging mechanisms	Baffle-former bolts	Volumetric (UT) examination Re-inspection every 10 years following initial inspection.	100% of accessible lower support column bolts (minimum of 75% of the total population), or as supported by plant-specific justification. (Note 4)	MRP-227A (confirmed in MRP-227, Rev. 1)

a. 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 is 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 are not feasible due to interference with the baffle plate structure.

b. In 2013 and 2014, UGW examinations on both units achieved 100% coverage due to the ability to perform the examination from the interior of the core barrel.

c. 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.

d. 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 the reactor cavity wall.

Notes:

1 Examination acceptance criteria and expansion criteria for the Westinghouse components are in Table 5-3 of MRP-227~~-A.~~, Revision 1.

2 The FMECA expert panel determined that Surry would follow MRP-227, Revision 1, for the expansion inspection components of the CRGT lower flange welds, which include the remaining CRGT lower flange welds and the BMI column bodies. The lower support columns (cast) and the upper core plate are added as Expansion links to the lower core barrel girth weld (Primary), and the lower core support forging is added as an Expansion link to the upper core barrel flange weld (Primary).

3 MRP-227-A specifies an EVT-1 examination for the upper core plate, lower support forging, and lower support columns (cast). It is noted that in MRP-227, Revision 1, the inspection technique for these components is changed to a visual (VT-3) examination.

4 ~~MRP-227-A Note: A minimum of 75% coverage of the entire examination area or volume, or a minimum sample size of 75% of the total population of like components of the examination is required (including both the accessible and inaccessible portions).~~ The stated minimum coverage is the minimum if no significant indications are found. However, the Examination Acceptance Criteria in Table 5-3 of MRP-227, Revision 1, require that additional coverage must be achieved in the same outage if significant flaws are found.

5 The examination coverage for the upper core plate, lower support forging, and lower support column bodies was redefined in MRP-227, Revision 1.

6 Remaining CRGT lower flange welds is added as an Expansion component in MRP-227, Revision 1, but as stated in Note 2 above, Surry will inspect in accordance with MRP-227, Revision 1 for this component.

7 MRP 2018-022 was issued on the baffle-former bolt expansion components which specifies that the lower support column bolts remain the first expansion component of the BFB unless a large cluster of BFB indications is discovered during the UT exams. The presence of clustering would trigger expansion of the barrel-former bolts adjacent to the large cluster of BFB indications due to the potential for clustering to result in indications of the barrel bolts. The terms "large cluster" and "barrel-former bolts adjacent to the cluster" are defined in MRP 2018-022.

8 The examination coverage for core barrel welds was redefined in MRP-227, Revision 1. MRP 2018-026, Table 4 (Note 3), states that 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".

9 Examination coverage requires examination of either the ID or the OD of the weld.

10 Accessibility of the MAW and the LAW may be limited by the thermal shield. No disassembly to achieve higher weld length coverage is required.

11 Justification that adequate distribution of the inspection coverage has been achieved can be based on geometric or layout arguments. Possible examples include, but are not limited to, inspection of all column assemblies in one quadrant of the lower core plate (based on the azimuthal symmetry of the plate) or inspecting every fourth column across the entire plate.

Table C4.3-3 Existing Programs Components

Item	Effect (mechanism)	Reference	Examination Method[a]	Examination Coverage	Source of Revision/ Addition
Control Rod Guide Tube Assembly Guide tube support pins and support pin nuts (Unit 1 only)	Cracking (SCC, Fatigue) Loss of material (wear) Irradiation embrittlement (IE) and Thermal and irradiation-induced stress relaxation (ISR/IC) are applicable aging mechanisms.	ASME Code Section XI	Visual (VT-3) examination	All accessible surfaces at specified frequency	MRP-227A (confirmed in MRP-227, Rev. 1)
Core Barrel Assembly Core barrel flange (surface)	Loss of material (wear)	ASME Code Section XI, Category B-N-3	Visual (VT-3) exam to determine general condition for excessive wear.	All accessible surfaces at specified frequency.	MRP-227A (confirmed in MRP-227, Rev. 1)
Upper Internals Assembly Upper support ring	Cracking (SCC, Fatigue)	ASME Code Section XI, Category B-N-3	Visual (VT-3) examination.	All accessible surfaces at specified frequency.	MRP-227A (confirmed in MRP-227, Rev. 1)
Upper Internals Assembly Fuel alignment pins (Malcomized)	Loss of material (wear)	ASME Code Section XI	Visual (VT-3) examination	All accessible surfaces at specified frequency.	Added by MRP 2018-022. See TB-16-4.
Lower Internals Assembly Lower core plate	Cracking (IASCC, Fatigue) Irradiation Embrittlement (IE) is an applicable aging mechanism.	ASME Code Section XI, Category B-N-3	Visual (VT-3) exam of the lower core plate to detect evidence of distortion and/or loss of bolt integrity.	All accessible surfaces at specified frequency.	Clarified with separate item created for wear by MRP-227, Rev. 1.
Lower Internals Assembly Lower core plate	Loss of material (wear)	ASME Code Section XI	Visual (VT-3) examination	All accessible surfaces at specified frequency.	Clarified with separate item created for wear by MRP-227, Rev. 1.
Lower Internals Assembly Fuel alignment pins (Malcomized)	Loss of material (wear)	ASME Code Section XI	Visual (VT-3) examination	All accessible surfaces at specified frequency.	Added by MRP 2018-022. See TB-16-4.
Bottom Mounted Instrumentation System Flux thimble tubes	Loss of material (wear)	IEB 88-09; Surry Augmented Inspection Program	Surface (ECT) examination.[b]	Eddy current surface examination for 100% of the accessible thimbles.	MRP-227A (confirmed in MRP-227, Rev. 1)
Alignment and Interfacing Components Upper core plate alignment pins	Loss of material (wear).	ASME Code Section XI	Visual (VT-3) examination.	All accessible surfaces at specified frequency.	MRP-227A (confirmed in MRP-227, Rev. 1)

a. Inspections for the components listed for Unit 1 were completed in November 2013. Inspections performed for Unit 2 were completed in May 2014.

b. Flux thimble tube inspections were completed in April 2015 for Unit 1 and in October 2015 for Unit 2. During the Unit 1 outage in 2015, 35 of the 50 flux thimble tubes were inspected using eddy current testing (ECT). 14 of those 15 remaining tubes were being replaced during that outage to complete the high pressure fitting / flux thimble tube replacement project that began in 2001. [The fifteenth tube would have been in location F-4, but that location had been capped in 2010 due to the inability to insert the new flux thimble tube]. Anomalies were noted in 2015 for two tubes identified as locations B7 and D7. For thimble tube B7, a through-wall pinhole leak was noted in the outer tube. The thimble tube was installed in 2004; an inspection in 2006 noted that thimble tube B-7 outer wall had been inadvertently damaged by plant personnel. Satisfactory eddy current results were obtained in 2015 for the inner tube which is the primary pressure boundary. Since the inner tube was not affected, thimble B-7 remained fully functional for flux mapping. For thimble tube D7, a dent is located approximately 5 feet below the seal table. Since the dent prevents the eddy current probe from passing, the thimble tube is no longer functional for passing an incore detector. The ECT for the Unit 2 flux thimble tubes found no indications of damage such as cracking and denting, or wall loss.

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