VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

April 14, 2020

10 CFR 50.90
10 CFR 50.91(a)(6)

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001

Serial No.:	20-136
NRA/GDM:	R0
Docket Nos.:	50-280/281
License Nos.:	DPR-32/37

VIRGINIA ELECTRIC AND POWER COMPANY
SURRY POWER STATION UNITS 1 AND 2
PROPOSED LICENSE AMENDMENT REQUEST
ONE-TIME DEFERRAL OF SURRY UNIT 2 STEAM GENERATOR "B" INSPECTION

The Surry Power Station (Surry) Unit 2 spring 2020 refueling outage (RFO) is scheduled to begin in May 2020. The RFO scope includes a planned inspection of steam generator (SG) "B" in accordance with the Technical Specifications (TS) requirements contained in TS 6.4.Q, "Steam Generator (SG) Program." Approximately ninety individuals, including 60-70 vendor personnel from across the United States, working in close proximity for extended periods of time, are required to perform the SG inspection activities. However, on January 31, 2020, the U.S. Department of Health and Human Services declared a public health emergency (PHE) for the United States to aid the nation's healthcare community in responding to the Coronavirus Disease 2019 (COVID-19). Subsequently, the COVID-19 outbreak was characterized as a pandemic by the World Health Organization on March 11, 2020. On March 12, 2020, the Commonwealth of Virginia declared a state of emergency, and on March 13, 2020, President Donald Trump declared the COVID-19 pandemic a national emergency. Consequently, in response to the pandemic declarations, in the interest of personnel safety, and to preclude the potential for transmittal and spread of the COVID-19 virus, Virginia Electric and Power Company (Dominion Energy Virginia) requests, on an exigent basis, a one-time deferral of the TS-required inspection of Surry Unit 2 SG "B".

Therefore, pursuant to 10 CFR 50.90 and 10 CFR 50.91(a)(6), Dominion Energy Virginia requests amendments to Surry Units 1 and 2 Facility Operating License Numbers DPR-32 and DPR-37, respectively, in the form of a change to the TS. This license amendment request (LAR) proposes a revision to Surry TS 6.4.Q to allow a one-time deferral of the inspection of Surry Unit 2 SG "B" from the spring 2020 RFO (S2R29) to the fall 2021 RFO (S2R30). Enclosure 1 provides a discussion of the proposed change, and Enclosures 2 and 3 provide the marked-up and proposed TS pages, respectively.

Dominion Energy Virginia has evaluated the proposed amendment and has determined it does not involve a significant hazards consideration as defined in 10 CFR 50.92. The basis for this determination is included in Enclosure 1. We have also determined operation with the proposed change will not result in a significant increase in the amount of effluents that may be released offsite or a significant increase in individual or cumulative occupational radiation exposure. Therefore, the proposed amendment is eligible for categorical exclusion from an environmental assessment as set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment is needed in connection with the approval of the proposed change. The LAR has been reviewed and approved by the Facility Safety Review Committee.

Dominion Energy Virginia requests approval of the proposed change by May 3, 2020.

Should you have any questions or require additional information, please contact Mr. Gary D. Miller at (804) 273-2771.

Respectfully,

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

Commitments contained in this letter:

1. Work is planned to be performed during RFO S2R29 on the Loose Parts Monitoring System secondary side monitoring channel to address nuisance alarms resulting from repeated signal spiking. Should the planned work not resolve the issue, the secondary side channel will be audibly monitored for evidence of abnormal noise until RFO S2R30.
2. In support of this one-time request to extend the interval between the Surry Unit 2 SG B inspections by one operating cycle, the primary-to-secondary leakage threshold will be reduced to a leak rate of 50 gallons per day attributable to Unit 2 SG B.

COMMONWEALTH OF VIRGINIA)
)
COUNTY OF HENRICO)

The foregoing document was acknowledged before me, in and for the County and Commonwealth aforesaid, today by Mr. Mark D. Sartain, who is Vice President – Nuclear Engineering 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 April, 2020.

My Commission Expires: March 31, 2022.

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

Diane E Aitken
Notary Public

Enclosures:

1. Discussion of Change
   - Attachment - Surry Unit 2 Steam Generator Operational Assessment Spring 2020 SG B Inspection Deferral, Revision 0
2. Marked-up Technical Specification Page
3. Proposed Technical Specification Page

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NRC Senior Resident Inspector
Surry Power Station

Enclosure 1

DISCUSSION OF CHANGE

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

DISCUSSION OF CHANGE

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DISCUSSION CHANGE

1.0 SUMMARY DESCRIPTION

Pursuant to 10 CFR 50.90 and 10 CFR 50.91(a)(6), Virginia Electric and Power Company (Dominion Energy Virginia) requests amendments to Surry Power Station (Surry) Units 1 and 2 Facility Operating License Numbers DPR-32 and DPR-37, respectively, in the form of a change to the Technical Specifications (TS). This license amendment request (LAR) proposes a one cycle revision to TS 6.4.Q, "Steam Generator (SG) Program." The proposed change adds a footnote to TS 6.4.Q.4.b to allow a one-time deferral of the inspection of Surry Unit 2 SG B from the spring 2020 refueling outage (RFO) (S2R29) to the fall 2021 RFO (S2R30).

The LAR is being submitted on an exigent basis due to the uncertainty of specialty vendor work force availability and to limit the risk of exposure to site/local supplemental workers resulting from the COVID-19 pandemic. Specifically, the nature of the SG inspection work prevents meeting the Centers for Disease Control and Prevention (CDC) recommendations for social distancing, e.g., craft support for closure assembly and disassembly, platform construction, robot manipulations, etc., which require multiple personnel to work in close proximity for extended periods of time to accomplish the work activities. Furthermore, industry vendors are supporting multiple overlapping outages utilizing limited personnel resources that are not readily replaceable due to their unique and complex qualifications. This vulnerability creates risks for which no contingencies exist. For example, inspections and subsequent actions require specialized personnel qualifications to complete. An outbreak affecting personnel that limits their availability once SG disassembly is complete and inspections have begun would result in failure to complete the TS required tube integrity examination scope and leave the station without the resources needed to reassemble the SG. Consequently, there is no "exit strategy" if an outbreak occurs mid-inspection. Therefore, a TS change is necessary to defer the SG B inspection until the following RFO.

2.0 DETAILED DESCRIPTION

2.1 System Design and Operation

The Surry Units 1 and 2 Reactor Coolant System (RCS) consists of three coolant loops. Each loop contains a reactor coolant pump (RCP), two loop stop valves, loop piping, instrumentation, and a SG. The SGs are Westinghouse Model 51F, and each SG is a vertical shell, U-tube heat exchanger that is the heat transfer interface between the primary and secondary loops. The purpose of the SGs is to generate high quality steam for the secondary plant by transferring heat from the reactor coolant to the secondary side water.

The SGs are divided into two main portions: the primary side and the secondary side. The primary side consists of a cast hemispherical chamber, internally partitioned by a divider plate, which separates the chamber into inlet and outlet chambers. The primary and secondary sides are separated by the tubesheet and the U-tubes. The tubesheet is penetrated by 3342 Inconel-600 thermally treated U-tubes, which are welded to the tubesheet. The tubes are supported at intervals by horizontal support plates. The locations of each tube are marked in accordance with an established grid system, i.e., row and column number. The marking of the tubes facilitates identification of tubes for plugging or inspection, thereby minimizing radiation exposure and time required for the activity.

Reactor coolant enters the primary side of the SG into the inlet chamber. The coolant then enters the U-tubes, flows up and through the tubes, exiting into the outlet chamber, where it returns to the RCP. The secondary side of the SG contains feedwater, recirculating water (hot water drainage from the first and second stage separators), and steam. The boundaries for the secondary side consist of the upper and lower shell, the top of the tubesheet and the outside of the U-tubes. An access opening for inspection and maintenance is provided in each section of the SG channel head.

2.2 Current Technical Specifications Requirements

Applicable SG TS requirements are included in the following TS sections:

- Specification 3.1.C, "RCS Operational LEAKAGE," limits primary to secondary leakage through any one SG to 150 gallons per day.

- Specification 3.1.H, "Steam Generator (SG) Tube Integrity," requires SG tube integrity be maintained, and all SG tubes satisfying the tube plugging criteria be plugged in accordance with the Steam Generator Program.

- Specification 4.19, "Steam Generator (SG) Tube Integrity," requires verification of SG tube integrity in accordance with the Steam Generator Program, and verification that any SG tube that satisfies the tube plugging criteria is plugged in accordance with the Steam Generator Program.

- Specification 6.4.Q, "Steam Generator (SG) Program," requires a SG tube program be established and implemented to ensure SG tube integrity is maintained. TS 6.4.Q.1 requires a condition monitoring assessment be performed during each outage in which the SG tubes are inspected to confirm the performance criteria are being met. TS 6.4.Q.2 ensures SG tube integrity is maintained by meeting specified performance criteria for structural and leakage integrity, consistent with the plant design and licensing bases. Meeting the SG performance criteria provides reasonable assurance of maintaining tube integrity at normal and accident conditions. TS 6.4.Q.3 includes SG tube plugging criteria, and TS 6.4.Q.4 includes provisions regarding the scope, frequency, and methods of SG tube inspections.

  TS 6.4.Q.4.b requires, in part, that "After the first refueling outage following SG installation, inspect each SG at least every 48 effective full power months or at least every other refueling outage (whichever results in more frequent inspections)."

2.3 Reason for Proposed Change

Surry Unit 2 is starting its spring 2020 RFO in May 2020, and the RFO scope includes a planned inspection of SG B to meet the requirements of TS 6.4.Q.4.b. Approximately ninety individuals, including 60-70 vendor personnel from across the United States, working in close proximity for extended periods of time, are required to perform the SG inspection activities. However, on January 31, 2020, the U.S. Department of Health and Human Services declared a public health emergency (PHE) for the United States to aid the nation's healthcare community in responding to the Coronavirus Disease 2019 (COVID-19). Subsequently, the COVID-19 outbreak was characterized as a pandemic by the World Health Organization on March 11, 2020. On March 12, 2020, the Commonwealth of Virginia declared a state of emergency, and on March 13, 2020, President Donald Trump declared the COVID-19 pandemic a national emergency.

Consequently, in response to the pandemic declarations, in the interest of personnel safety, and to preclude the potential for transmittal and spread of the COVID-19 virus, Dominion Energy Virginia is seeking, on an exigent basis, a one-time deferral of the TS-required inspection of Surry Unit 2 SG B to the next Surry Unit 2 RFO in fall 2021 (S2R30). The Unit 2 A and C SGs were inspected during the fall 2018 Unit 2 RFO and are therefore not required to be inspected during the 2020 RFO. Consequently, the TS-required inspection schedule for the Unit 2 A and C SGs is not affected by the proposed change.

2.4 Description of Proposed Change

A note will be added to TS 6.4.Q.4.b to permit a one-time deferral of the Surry Unit 2 SG B inspection as follows (added text in **BOLD** type):

b. After the first refueling outage following SG installation, inspect each SG at least every 48 effective full power months or at least every other refueling outage (whichever results in more frequent inspections).*...

* **As approved by Amendment Nos. XXX and XXX, the inspection of Surry Unit 2 SG B may be deferred, on a one-time basis, from the Surry Unit 2 spring 2020 refueling outage (S2R29) to the Surry Unit 2 fall 2021 refueling outage (S2R30).**

3.0 TECHNICAL EVALUATION

Surry TS 6.4.Q.4.b requires that after the first RFO following SG installation, each SG must be inspected at least every 48 effective full power months (EFPM) or at least every other RFO (whichever results in more frequent inspections). Surry Unit 2 SG B was last inspected during the spring 2017 RFO (S2R27) and would therefore need to be inspected during the spring 2020 RFO (S2R29) to comply with the TS 6.4.Q.4.b requirement, "...at least every other refueling outage..." Surry TS 6.4.Q.4.b further stipulates that commencing with the third inspection period during the remaining life of the SGs, 100% of the tubes in each SG must be inspected every 72 EFPM. 100% of the Unit 2 'B' SG tubes were inspected during the spring 2017 RFO. Surry Unit 2 SGs are now in the 5th Inspection period (duration 72 EFPM). The fall 2018 RFO (S2R28) was the first outage of the 5th period.

Due to personnel safety issues associated with the COVID-19 pandemic as discussed above, Dominion Energy Virginia is requesting a one-time change to Surry TS 6.4.Q.4.b requirements to defer the SG B inspection by one RFO.

3.1 Operational Assessment Summary

The Dominion Energy Steam Generator Program requires a "forward looking" operational assessment (OA) be performed to determine if the SG tubing will continue to meet specific structural and leakage integrity performance criteria throughout the operating period preceding the next inspection. NEI 97-06, "Steam Generator Program Guidelines," (Reference 8.1) and TS 6.4.Q establish the following SG performance criteria:

- Structural Integrity – Margin of 3.0 against burst under normal steady state power operation, and a margin of 1.4 against burst under the most limiting design basis accident. Additional requirements are specified for non-pressure accident loads.
- Operational Leakage – RCS operational primary-to-secondary leakage through one SG shall not exceed 150 gallons per day (gpd).
- Accident Induced Leakage – Leakage shall not exceed the value assumed in the limiting accident analysis (470 gpd).

The OA (Reference 8.5) is provided in the attachment to this enclosure and was performed in accordance with the following Surry and industry inspection requirements' documents:

- Surry Technical Specifications (TS 6.4.Q)
- Dominion Energy fleet-wide SG Program
- NEI 97-06, "Steam Generator Program Guidelines"
- EPRI Steam Generator Integrity Assessment Guidelines (IAG) (Reference 8.2)
- Dominion Energy SG Condition Monitoring and Operational Assessment (CMOA) Procedure

The OA provides an evaluation of Surry Unit 2 SG B for the purpose of demonstrating the primary side examinations currently planned for the end of cycle (EOC)29 (May 2020) may be safely deferred by one additional operating cycle to EOC30.

SGs A and C were inspected more recently (EOC28, fall 2018) than SG B, and the OA performed following the EOC28 inspection concluded SGs A and C could be safely operated until their next scheduled primary side inspection at EOC30. Consequently, the OA does not include any additional analysis of SGs A and C.

Table 1 below provides a brief description of the Surry Unit 2 SG inspections performed, or to be performed, from the spring 2017 RFO through the fall 2021 RFO. As discussed above, the purpose of the OA is to determine if the planned EOC29 SG B primary side inspections may be safely deferred until EOC30. Table 1 shows the as-planned scope prior to the proposed deferral. In addition to the deferral of the SG B primary inspection scope, the secondary side inspections planned for the three SGs in EOC29 would also be deferred to EOC30. The "full primary side inspection scope" referred to in the table includes 100% full length bobbin probe examinations (excluding low row u-bends), 100% hot leg and cold leg tubesheet region array probe exams, +Point™ probe examinations of the low row u-bends, and miscellaneous +Point™ probe exams in areas of special interest.

Table 1: Surry Unit 2 Inspection Scope Timeline

Refueling Outage	Date	Inspection Scope		
		SG A	**SG B**	**SG C**
EOC27	Spring 2017	• Array probe, 100% hot leg tubesheet region • TTS SSI / FOSAR	• Full primary side inspection scope • TTS SSI / FOSAR	• Array probe, 100% hot leg tubesheet region • TTS SSI / FOSAR • Upper internals SSI
EOC28	Fall 2018	• Full primary side inspection scope • TTS SSI / FOSAR	• Upper internals SSI	• Full primary side inspection scope • TTS SSI / FOSAR
EOC29	Spring 2020	• TTS SSI / FOSAR • Upper internals SSI	• Full primary side inspection scope • TTS SSI / FOSAR	• TTS SSI / FOSAR
EOC30	Fall 2021	• Full primary side inspection scope • TTS SSI / FOSAR	• No primary side inspections planned • TTS SSI / FOSAR	• Full primary side inspection scope • TTS SSI / FOSAR • Upper internals SSI

(Note: The acronyms included in the above and following tables and text are defined in the attached OA.)

The degradation mechanisms assessed during the most recent inspections are identified in the respective 180-day reports for EOC27 and EOC28 (References 8.3 and 8.4, respectively). The degradation mechanisms previously identified (i.e., "existing") in the Unit 2 SGs, and the inspection method and scope used to detect these mechanisms, are summarized in Table 2. Three degradation mechanisms not identified in the Unit 2 SGs, but considered potential degradation mechanisms, are summarized in Table 3. Each of the degradation mechanisms identified in these tables is evaluated within the attached OA.

Table 2: Existing Surry Unit 2 Degradation Mechanisms

Mechanism	Detection Strategy
Circumferential primary side stress corrosion cracking (PWSCC) within the tubesheet expansion	• 100% hot and cold leg array probe examination of the tubesheet region
Anti-vibration bar (AVB) wear	• 100% bobbin probe examination of AVB/tube intersections
Foreign object wear	• 100% hot and cold leg array probe examination of the tubesheet region. • 100% full length bobbin probe examination
Tube support plate (TSP) and flow distribution baffle (FDB) wear	• 100% bobbin probe examination of TSP/tube intersections
Pitting at TTS	• 100% hot and cold leg array probe examination of the tubesheet region. • 100% full length bobbin probe examination

Table 3: Potential Degradation Mechanisms

Mechanism	Detection Strategy
Circumferential OD stress corrosion cracking (ODSCC) at the top of tubesheet (TTS)	• 100% hot and cold leg array probe examination of the tubesheet region
Axial primary side stress corrosion cracking (PWSCC) at the TTS	• 100% hot and cold leg array probe examination of the tubesheet region
Axial ODSCC at TSPs	• 100% bobbin probe examination of TSP/tube intersections • 100% array probe examination of hot leg TSP/tube intersections in high stress tubes

The OA considers axial outer-diameter stress corrosion cracking (ODSCC) within tube support plates (TSP), which is considered bounding for axial stress corrosion cracking at other locations for three reasons. First, eddy current bobbin probe examination methods are relied upon to detect this mechanism in non-high stress tubes. The bobbin probe probability of detection (POD) is less favorable than the POD of the +Point™ or array probes that are used at the top of tubesheet and other discrete areas of interest. Second, the crack length utilized in this analysis corresponds to the full thickness of the tubesheet plate (TSP) (1.12"), which bounds the lengths of cracks typically identified in other locations of the SG. Third, the elevated residual hoop stress associated with the high stress tubes may result in higher crack depth growth rates once initiated at these locations.

The distribution of EOC30 worst-case degraded tube burst pressures resulting from this analysis is provided in the attached OA. The OA demonstrates that the 5th percentile burst pressure for the evaluated degradation mechanisms satisfies the structural integrity performance criteria (SIPC) limit of 4,470 pounds per square inch (psi). It is therefore concluded the SIPC will not be exceeded in SG B prior to EOC30. Additionally, the total upper 95/50 leakage resulting from the analyses is zero. As such, it is concluded none of the evaluated degradation mechanisms will cause the accident-induced leakage performance criteria (AILPC) to be exceeded prior to EOC30.

Table 4 summarizes the projected margin to SIPC and AILPC analysis captured in the attached OA.

Table 4: SG B Integrity Margin Summary

Degradation Mechanism	SIPC		AILPC	
	Limit	EOC30 Projection	Limit	EOC30 Projection
Circumferential PWSCC within the tubesheet expansion[1]	64 PDA	45.4 PDA	90.3 %TW Pop-Through Depth	88 %TW Maximum Depth
AVB wear	64 %TW	38.8 %TW Maximum Depth	470 GPD	Zero Leakage
Foreign object wear	72 %TW	30 %TW Maximum Depth	470 GPD	Zero Leakage
TSP/FDB wear	56.6 %TW	41.5 %TW Maximum Depth	470 GPD	Zero Leakage
Pitting	Dormant. No projected pitting.			
Circumferential ODSCC @TTS	74.6 PDA	37.1 PDA	91.6 %TW Pop-Through Depth	73.1 %TW Maximum Depth
Axial PWSCC @TTS	4470 psi[2]	5546 psi	470 GPD	Zero Leakage
Axial ODSCC @TSPs	4470 psi[2]	5342 psi	470 GPD	Zero Leakage

[1] The beneficial presence of the tubesheet is not credited in the evaluation.

[2] Minimum acceptable burst pressure.

In the absence of degradation projected to exceed the AILPC during the next operating period, there is reasonable assurance that normal operating conditions will not lead to a violation of the operational leakage performance criteria. Although there are no known conditions of concern, sensitivity to primary-to-secondary leakage events will continue under Surry's conservative monitoring procedures.

Based on the above, there is reasonable assurance the SIPC and AILPC will remain satisfied in SG B throughout the period preceding EOC30 for a total operating duration of three cycles between primary side inspections.

Additional information relevant to this operational assessment summary is provided below:

Surry Unit 2 Tube Plugging. The total number of tubes plugged along with the driver for each is provided in Tables 5 and 6:

Table 5: Total Number of SG Tubes Plugged in Surry Unit 2

	SG A	SG B	SG C	Total
Total Tubes Plugged Through S2R28	30	19	50	99
Percent Tubes Plugged Through S2R28	0.89%	0.56%	1.49%	0.98%
Allowable Percent Tubes Plugged	7%	7%	7%	7%

Table 6: Surry Unit 2 SG Tube Degradation Mechanisms

Degradation Mode	SG-A	SG-B	SG-C	Total
AVB Wear	1	5	10	16
Foreign Object	11	7	20	38
Pitting	11	0	1	12
SCC (excluding tube-end)	0	0	3	3
Tube-end SCC	3	1	2	6
Other*	4	6	14	24

* Shop plugs, restricted tubes, permeability variations, and 11 tubes plugged due to incomplete hydraulic expansions required due to a One-Time Alternative Repair Criteria (ARC).

No tubes have required plugging in Surry Unit 2 steam generators since S2R26 (2015) at which time a total of six tubes were plugged to address the first instance of tube-end SCC.

High Stress Tubes: A total of two high stress tubes exist in Surry Unit 2 SG B. During EOC27, Surry examined the entire hot leg straight length of tubing along with the cold leg tube sheet region in the two SG B high stress tubes using an array probe. No relevant indications were noted. When analyzing existing and potential stress corrosion cracking degradation mechanisms, the attached OA utilizes the POD associated with the bobbin probe method of examination for the purposes of defining a pre-existing flaw size used for probabilistic crack growth analysis. This POD is conservative when compared to that of the array probe method used to examine the existing high stress tubes, and the approach was applied to all SG tubes to account for any unidentified high stress tubes. To add further conservativism, the higher crack growth rates applicable to the evaluation of high stress tubes are conservatively applied for all tube TSP region axial ODSCC analyses even though there are only two high stress tubes in SG B.

Deposit Loading: Deposit loading has been aggressively managed including performance of DMT in 2009 and deposit mapping each outage since that time. No adverse trends in deposit loading currently exist in any Unit 2 SG.

Chemistry Transients: No chemistry excursions have occurred in Surry Unit 2 throughout the operating interval since S2R27 (2017).

Introduction of FME: No known foreign materials that pose a threat to tube integrity are known to exist in any of the Unit 2 SGs. No incidents of foreign material introduction to the Unit 2 primary or secondary fluid systems are known to have occurred throughout the operating interval since S2R27 (2017).

3.2 Mitigation Strategy

The TS limit on primary-to-secondary leakage is 150 gpd through any one SG. The limit of 150 gpd per SG is based on the operational leakage performance criterion prescribed in NEI 97-06, Steam Generator Program Guidelines. The limit is based on operating experience with SG tube degradation mechanisms that result in tube leakage. The operational leakage rate criterion in conjunction with the implementation of the Steam Generator Program is an effective measure for minimizing the frequency of SG tube ruptures.

There are several methods available to identify and quantify primary-to-secondary leakage in the plant. These methods include continuous radiation monitoring via Nitrogen-16 (N-16) radiation monitors, Main Condenser Air Ejector radiation monitors, and Steam Generator blowdown radiation monitors. The advantage of continuous radiation monitors is they provide instant response during a primary-to-secondary leak. Additionally, the N-16 radiation monitors can provide evidence to determine from which SG the leak is originating.

Throughout the extended interval between inspections, support systems will continue to be monitored for evidence indicative of a SG tube leak. For the Unit 2 SG B, both primary side and secondary side loose parts monitoring channels are functional and will be monitored for indications of potential tube degradation caused by contact with impinging loose foreign materials. The secondary side channel alarm function is currently disabled to mitigate periodic nuisance alarms resulting from repeated signal spiking. This channel is monitored twice each day for abnormal noises. Work is planned to be performed during the spring 2020 (S2R29) RFO on the secondary side monitoring channel to address the signal spiking issue. Should the planned work be unable to resolve the issue, the secondary side channel will continue to be audibly monitored twice each day for evidence of abnormal noise.

The Unit 2 Main Condenser Air Ejector radiation monitor is the primary means of monitoring and assessing primary-to-secondary leakage, augmented by three N-16 Main Steam Radiation monitor channels, one installed in each steam generator main steam supply line. All channels are functional, continuously monitoring for evidence of primary-to-secondary leakage and augmented by daily performance of primary-to-secondary system leakage calculations. Current calculations indicate no detectible leakage has been identified in any Unit 2 steam generator. When total primary-to-secondary leakage reaches 5 gpd, increased monitoring is initiated. Should leakage increase to 30 gpd, actions are initiated to frequently monitor the leak rate, trend the leak rate and confirm the leakage source. If the leak rate reaches 75 gpd, actions are initiated to shut the affected unit down within 24 hours. In support of this one-time request to extend the interval between the SG B inspections by one operating cycle, this threshold will be reduced to a leak rate of 50 gpd attributable to Unit 2 SG B.

The above monitors and actions will provide assurance that should a SG tube leak develop in the Unit 2 SG B, the condition will be identified and managed to ensure public safety is assured. The leakage limits imposed are in line with EPRI recommendations and conservatively below the TS prescribed shutdown criteria of 150 gpd.

4.0 REGULATORY EVALUATION

As noted above, the proposed change adds a note to Technical Specification (TS) 6.4.Q.4.b to permit a one-time deferral of the Surry Unit 2 SG B inspection from the Surry Unit 2 spring 2020 refueling outage (2R29) to the Surry Unit 2 fall 2021 refueling outage (RFO) (2R30). The following regulatory requirements have been reviewed and a No Significant Hazards Consideration Determination has been performed as discussed below.

4.1 Applicable Regulatory Requirements/Criteria

Technical Specifications - Section 50.36 of Title 10 of the *Code of Federal Regulations* (10 CFR), establishes the regulatory requirements related to the content of the TSs. Pursuant to 10 CFR 50.36, TSs are required to include items in the following five specific categories related to station operation: (1) safety limits, limiting safety system settings, and limiting control settings; (2) limiting conditions for operation (LCOs); (3) surveillance requirements; (4) design features; and (5) administrative controls. In 10 CFR 50.36(c)(5), administrative controls are stated to be, "the provisions relating to organization and management, procedures, recordkeeping, review and audit, and reporting necessary to assure the operation of the facility in a safe manner." This also includes the programs established by the licensee and listed in the administrative controls section of the TS for the licensee to operate the facility in a safe manner. For Surry Units 1 and 2, the requirements for performing SG tube inspections and repair are in TS 3.1.H, "Steam Generator (SG) Tube Integrity," TS 4.19, "Steam Generator (SG) Tube Integrity," and TS 6.4.Q, "Steam Generator (SG) Program."

The TSs for pressurized-water reactor plants require that a SG program be established and implemented to ensure SG tube integrity is maintained. For Surry Units 1 and 2, SG tube integrity is maintained by meeting specified performance criteria (TS 6.4.Q.2) for structural and leakage integrity, consistent with the plant design and licensing basis. TS 6.4.Q.1 requires that a condition monitoring assessment be performed during each outage in which the SG tubes are inspected, to confirm that the performance criteria are being met. TS 6.4.Q.4 also includes provisions regarding the scope, frequency, and methods of SG tube inspections. Of relevance to this license amendment request, TS 6.4.Q.4.b requires, in part, that "After the first refueling outage following SG installation, inspect each SG at least every 48 effective full power months or at least every other refueling outage (whichever results in more frequent inspections)."

<u>10 CFR Requirements/General Design Criteria</u> - The regulations in Appendix A to Title 10 of the Code of Federal Regulations (10 CFR) Part 50 establish minimum principal design criteria for water-cooled nuclear power plants, while 10 CFR 50 Appendix B and the licensee quality assurance programs establish quality assurance requirements for the design, manufacture, construction, and operation of structures, systems, and components.

During the initial plant licensing of Surry Units 1 and 2, it was demonstrated that the design of the reactor coolant pressure boundary, including the steam generators, met the regulatory requirements in place at that time. The General Design Criteria (GDC) included in Appendix A to 10 CFR Part 50 did not become effective until May 21, 1971. The Construction Permit for Surry Unit 2 was issued prior to May 21, 1971; consequently, this unit was not subject to GDC requirements. (Reference SECY-92-223 dated September 18, 1992.) However, the following information demonstrates compliance with GDC 14, 15, 30, 31, and 32 of 10 CFR 50, Appendix A. Specifically, the GDC state that the Reactor Coolant Pressure Boundary (RCPB) shall have "an extremely low probability of abnormal leakage . . . and gross rupture" (GDC 14), "shall be designed with sufficient margin" (GDCs 15 and 31), shall be of "the highest quality standards practical" (GDC 30), and shall be designed to permit "periodic inspection and testing . . . to assess . . . structural and leak tight integrity" (GDC 32). Structural integrity refers to maintaining adequate margins against burst and collapse of the steam generator tubing. Leakage integrity refers to limiting primary-to-secondary leakage during all plant conditions to within acceptable limits.

The reactor coolant pressure boundary is designed, fabricated and constructed to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime. Reactor coolant pressure boundary components have provisions for the inspection testing and surveillance of critical areas by appropriate means to assess the structural and leaktight integrity of the boundary components during their service lifetime. The SG tubes function as an integral part of the reactor coolant pressure boundary (RCPB) and, in addition, isolate fission products in the primary coolant from the secondary coolant and the environment. SG tube integrity means the tubes are capable of performing these safety functions in accordance with the plant design and licensing bases. All applicable regulatory requirements will continue to be satisfied as a result of the proposed license amendment.

As part of the plant-licensing basis, applicants for operating licenses are required to analyze the consequences of postulated design-basis accidents (DBA) such as a SG tube rupture and a main steam line break (MSLB). These analyses consider primary-to-secondary leakage that may occur during these events and must show that the offsite radiological consequences do not exceed the applicable limits of the 10 CFR 50.67 guidelines for offsite doses, GDC 19 criteria for control room operator doses, or some fraction thereof as appropriate to the accident, or the NRC-approved licensing basis (e.g., a small fraction of these limits). No accident analysis for Surry Units 1 and 2 is being changed because of the proposed amendment; thus, no radiological consequences of any accident analysis are being changed. The proposed change to TS 6.4.Q stays within the GDC requirements for the SG tubes and maintains the accident analysis and consequences for the postulated DBAs for SG tubes.

4.2 No Significant Hazards Consideration Determination

Virginia Electric and Power Company (Dominion Energy Virginia) is proposing a TS change to add a note to TS 6.4.Q.4.b to permit a one-time deferral of the Surry Unit 2 SG B inspection from the Surry Unit 2 spring 2020 refueling outage (RFO) (S2R29) to the Surry Unit 2 fall 2021 refueling outage (S2R30). Dominion Energy Virginia has evaluated whether a significant hazards consideration is involved with the proposed amendment by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of Amendment," as discussed below:

(1) Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

Response: No

The proposed change adds a note to TS 6.4.Q.4.b to permit a one-time deferral of the Surry Unit 2 SG B inspection from the Surry Unit 2 spring 2020 refueling outage (RFO) (S2R29) to the Surry Unit 2 fall 2021 refueling outage (S2R30). An operational assessment has been performed that concludes Surry Unit 2 SG B will continue to meet its specific structural and leakage integrity performance criteria throughout the operating period preceding the next inspection in fall 2021. In addition, the proposed change does not implement plant physical changes to any plant structure, system or component; hence, no new failure modes are introduced. Therefore, the probability of an accident previously evaluated is not significantly increased. Also, there is no significant increase in the consequences of an accident because the TS primary-to-secondary leakage limit is not being changed, and the SG tubes continue to meet the SG Program performance criteria and remain bounded by the plant's accident analyses.

Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

(2) Does the proposed change create the possibility of a new or different accident from any accident previously evaluated?

Response: No

The proposed change adds a note to TS 6.4.Q.4.b to permit a one-time deferral of the Surry Unit 2 SG B inspection from the Surry Unit 2 spring 2020 refueling outage (RFO) (S2R29) to the Surry Unit 2 fall 2021 refueling outage (S2R30). The proposed change does not alter the design function or operation of the SGs or the ability of a SG to perform its design function. The SG tubes continue to meet the SG Program performance criteria. No plant physical changes are being implemented that would result in plant operation in a configuration outside the plant safety analyses or design basis. The proposed change does not introduce any changes or mechanisms that create the possibility of a new or different kind of accident. Furthermore, Surry Unit 2 SG B will continue to meet its specific structural and leakage integrity performance criteria throughout the operating period preceding the next inspection in fall 2021. Finally, no new effects on existing equipment are created nor are any new malfunctions introduced.

Therefore, based on the above evaluation, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

(3) Does the proposed change involve a significant reduction in a margin of safety?

Response: No

The proposed change adds a note to TS 6.4.Q.4.b to permit a one-time deferral of the Surry Unit 2 SG B inspection from the Surry Unit 2 spring 2020 refueling outage (RFO) (S2R29) to the Surry Unit 2 fall 2021 refueling outage (S2R30). Extending the Surry Unit 2 SG B inspection schedule does not involve changes to any limit on accident consequences specified in the Surry licensing bases or applicable regulations, does not modify how accidents are mitigated, and does not involve a change in a methodology.

A forward-focused operational assessment (OA) of Surry Unit 2 SG B was performed that demonstrates there is reasonable assurance the structural integrity and accident induced leakage performance criteria will remain satisfied in SG B throughout the period preceding the fall 2021 RFO inspection for a total operating duration of three cycles between primary side inspections. The OA also identified projected margin to the structural integrity and accident induced leakage performance criteria prior to the fall 2021 RFO for each evaluated degradation mechanism.

Therefore, operation of the facility in accordance with the proposed change will not involve a significant reduction in a margin of safety.

Therefore, Dominion Energy Virginia concludes the proposed amendment presents no significant hazards consideration under the standards set forth in 10 CFR 50.92(c) and, accordingly, a finding of "no significant hazards consideration" is justified.

5.0 PRECEDENTS

Similar LARs requesting the deferral of SG inspections for one cycle are currently under review by the NRC as noted below:

5.1 Letter from Florida Power and Light to the US NRC dated April 4, 2020, "RE: Turkey Point Nuclear Plant, Unit 3, Docket No. 50-250, Renewed Facility Operating License DPR-31, Exigent License Amendment Request 272, One-Time Extension of TS 6.8.4 Steam Generator Inspection Program."

5.2 Letter from Exelon Generation to the US NRC dated April 6, 2020, "Subject: Emergency License Amendment Request for a One-Time Extension of the Steam Generator Tube Inspections."

The following letters are precedence for one-time changes to SG inspection frequencies:

5.3 Letter from US NRC to STP Nuclear Operating Company dated June 8, 2004, "South Texas Project, Unit 1 – Issuance of Amendment RE: One-Time Extension of the Steam Generator Inspection Frequency (TAC No. MC1046)," (ML041610073).

5.4 Letter from US NRC to South Carolina Electric & Gas Company dated October 29, 2003, "Virgil C. Summer Nuclear Station, Unit 1 – Issuance of Amendment RE: One-Time Extension of the Steam Generator Inspection Frequency (TAC No. MB7312)," (ML033020450).

5.5 Letter from US NRC to Entergy Operations, Inc. dated May 28, 2003, "Arkansas Nuclear One, Unit 2 – Issuance of Amendment RE: One-Time Extension of the Steam Generator Inspection Frequency (TAC No. MB6808)," (ML031490475).

6.0 ENVIRONMENTAL CONSIDERATION

The proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9) asfollows:

(i) The proposed change involves no significant hazards consideration.

As described in Section 4.2 above, the proposed change involves no significant hazards consideration.

(ii) There are no significant changes in the types or significant increase in the amounts of any effluents that may be released off-site.

The proposed change adds a note to TS 6.4.Q.4.b to permit a one-time deferral of the Surry Unit 2 SG B inspection from the Surry Unit 2 2020 refueling outage (2R29) to the Surry Unit 2 2021 refueling outage (2R30). The proposed change does not alter the design function or operation of the SGs or the ability of a SG to perform its design function. SG B will continue to meet specific structural and leakage integrity performance criteria throughout the operating period preceding the next inspection in fall 2021. As such, the proposed change does not involve the installation of any new equipment or the modification of any equipment that may affect the types or amounts of effluents that may be released off-site. The proposed change will have no impact on normal plant releases and will not increase the predicted radiological consequences of accidents postulated in the UFSAR. Therefore, there are no significant changes in the types or significant increase in the amounts of any effluents that may be released off-site.

(iii) There is no significant increase in individual or cumulative occupational radiation exposure.

The proposed change adds a note to TS 6.4.Q.4.b to permit a one-time deferral of the Surry Unit 2 SG B inspection from the Surry Unit 2 2020 refueling outage (2R29) to the Surry Unit 2 2021 refueling outage (2R30). The proposed change does not implement plant physical changes or result in plant operation in a configuration outside the plant safety analyses or design basis. Furthermore, SG B will continue to meet specific structural and leakage integrity performance criteria throughout the operating period preceding the next inspection in fall 2021. Therefore, there is no significant increase in individual or cumulative occupational radiation exposure associated with the proposed change.

Based on the above, Dominion Energy Virginia concludes that, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

7.0 CONCLUSION

The proposed change adds a footnote to TS 6.4.Q.4.b to allow a one-time deferral of the inspection of Surry Unit 2 steam generator 'B' from the 2020 spring refueling outage (RFO) (2R29) to the fall 2021 RFO (2R30). The proposed change will not result in plant operation in a configuration outside the current design basis and does not affect the safety analyses. The structural integrity and known degradation mechanisms of the SG-B tubes have been evaluated, and it has been determined the SG tube integrity performance criteria will continue to be met until the fall 2021 RFO when the next inspection will be performed.

Therefore, Dominion Energy Virginia concludes, based on the considerations discussed herein, that (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

8.0 REFERENCES

8.1 Nuclear Energy Institute (NEI) 97-06 Revision 3, "Steam Generator Program Guidelines," January 2011.

8.2 Electric Power Research Institute (EPRI) Report 3002007571, "Steam Generator Management Program: Steam Generator Integrity Assessment Guidelines," Revision 4, June 2016

8.3 Letter from Virginia Electric and Power Company to the USNRC dated October 26, 2017 (ADAMS Accession No. ML17310A235), Serial No. 17-415, "Virginia Electric and Power Company, Surry Power Station Unit 2, Steam Generator Tube Inspection Report for the Spring 2017 Refueling Outage."

8.4 Letter from Virginia Electric and Power Company to the USNRC dated May 16, 2019 (ADAMS Accession No. ML179154A353), Serial No. 19-153, "Virginia Electric and Power Company, Surry Power Station Unit 2 Steam Generator Tube Inspection Report for the Fall 2018 Refueling Outage."

8.5 Surry Unit 2 Steam Generator Operational Assessment Spring 2020 SG B Inspection Deferral, Revision 0.

8.6 Surry Power Station Units 1 and 2 UFSAR Chapters 4, "Reactor Coolant System," and 10, "Steam and Power Conversion."

Attachment

SURRY UNIT 2 STEAM GENERATOR OPERATIONAL ASSESSMENT SPRING 2020 SG B INSPECTION DEFERRAL, REVISION 0

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

Surry Unit 2 Steam Generator Operational Assessment Spring 2020 SG B Inspection Deferral

Revision 0

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1.0 PURPOSE

This report provides an operational assessment (OA) of Surry Unit 2 (SPS2) steam generator (SG) B. The purpose is to demonstrate that the primary side examinations currently planned for the end of Cycle 29 (EOC29) (May 2020) may be safely deferred by one additional operating cycle to EOC30.

SG A and SG C were inspected more recently (EOC28, fall 2018) than SG B, and the OA performed following the EOC28 inspection [3.d] concluded that SGs A and C could be safely operated until their next scheduled primary side inspection at EOC30. Consequently, this OA does not include any additional analysis of SGs A and C.

2.0 BACKGROUND

2.1 Inspection Timeline

Table 2-1 provides a brief description of the Surry Unit 2 SG inspections performed or to be performed from the spring 2017 outage through the fall 2021 outage. As discussed above the purpose of this OA is to determine if the planned EOC29 SG B primary side inspections may be safely deferred until EOC30. The table shows the scope as-planned prior to the deferral. In addition to the deferral of the SG B primary inspection scope, the secondary side inspections planned for all three SGs in EOC29 would also be deferred to EOC30. The "full primary side inspection scope" referred to in the table includes 100% full length bobbin probe examinations (excluding low row u-bends), 100% hot leg and cold leg tubesheet region array probe exams, +point probe examinations of the low row u-bends, and miscellaneous +point probe exams in areas of special interest.

Table 2-1: Surry Unit 2 Inspection Scope Timeline

Refueling Outage	Date	Inspection Scope			
		SG A	SG B	SG C	
EOC27	Spring 2017	• Array probe, 100% hot leg tubesheet region • TTS SSI / FOSAR	• Full primary side inspection scope • TTS SSI / FOSAR	• Array probe, 100% hot leg tubesheet region • TTS SSI / FOSAR • Upper internals SSI	
EOC28	Fall 2018	• Full primary side inspection scope • TTS SSI / FOSAR	• Upper internals SSI	• Full primary side inspection scope • TTS SSI / FOSAR	
EOC29	Spring 2020	• No primary side inspections planned • TTS SSI / FOSAR • Upper internals SSI	• Full primary side inspection scope • TTS SSI / FOSAR	• No primary side inspections planned • TTS SSI / FOSAR	Original Plan
EOC30	Fall 2021	• Full primary side inspection scope • TTS SSI / FOSAR	• No primary side inspections planned • TTS SSI / FOSAR	• Full primary side inspection scope • TTS SSI / FOSAR • Upper internals SSI	Original Plan

2.2 Degradation Mechanisms

The degradation mechanisms targeted by the most recent inspections are identified in the respective 180-day reports [3.g, 3.h] for EOC27 and EOC28. The degradation mechanisms previously identified (i.e., "existing") in the Unit 2 SGs and the inspection method and scope used to detect these mechanisms are summarized in Table 2-2. Two degradation mechanisms have been identified in the Surry Unit 1 SGs that have not been identified in the Unit 2 SGs. They are summarized in Table 2-3. Each of the degradation mechanisms identified in these tables are evaluated within this OA.

In addition to these mechanisms, the OA also considers axial ODSCC within TSPs (Table 2-4). This degradation mechanism is considered to be bounding of axial stress corrosion cracking at other locations for three reasons. First, ECT bobbin probe examination methods are relied upon to detect this mechanism in non-high stress tubes. The bobbin probe POD is less favorable than that of the +point or array probes which are used at the top of tubesheet and other discrete areas of interest [3.b]. Second, the crack length utilized in this analysis corresponds to the full thickness of the TSP (1.12") which bounds the lengths of cracks typically identified in other locations of the SG. Third, the elevated residual hoop stress associated with the high stress tubes may result in higher crack depth growth rates once initiated at these locations.

Table 2-2: Existing SPS2 Degradation Mechanisms

Mechanism	Detection Strategy
Circumferential primary side stress corrosion cracking (PWSCC) within the tubesheet expansion	• 100% hot and cold leg array probe examination of the tubesheet region
Anti-vibration bar (AVB) wear	• 100% bobbin probe examination of AVB/tube intersections
Foreign object wear	• 100% hot and cold leg array probe examination of the tubesheet region. • 100% full length bobbin probe examination
Tube support plate (TSP) and Flow distribution baffle (FDB) wear	• 100% bobbin probe examination of TSP/tube intersections
Pitting at TTS	• 100% hot and cold leg array probe examination of the tubesheet region. • 100% full length bobbin probe examination

Table 2-3: Degradation Mechanisms Identified in SPS1 but not in SPS2

Mechanism	Detection Strategy
Circumferential OD stress corrosion cracking (ODSCC) at the top of tubesheet (TTS)	• 100% hot and cold leg array probe examination of the tubesheet region
Axial primary side stress corrosion cracking (PWSCC) at the TTS	• 100% hot and cold leg array probe examination of the tubesheet region

Table 2-4: Other Evaluated Degradation Mechanism

Mechanism	Detection Strategy
Axial ODSCC at TSPs	• 100% bobbin probe examination of TSP/tube intersections. • 100% array probe examination of hot leg TSP/tube intersections in high stress tubes

2.3 Regulatory Requirements

Technical Specification 6.4.Q and the Dominion SG program [3.a] require that a "forward looking" operational assessment (OA) be performed to determine if the steam generator tubing will continue to meet specific structural and leakage integrity performance criteria throughout the operating period preceding the next inspection. NEI 97-06 [1] and Technical Specification TS 6.4.Q establish these steam generator performance criteria:

- Structural Integrity – Margin of 3.0 against burst under normal steady state power operation and a margin of 1.4 against burst under the most limiting design basis accident. Additional requirements are specified for non-pressure accident loads.
- Operational Leakage – RCS operational primary-to-secondary leakage through one steam generator shall not exceed 150 GPD.
- Accident Induced Leakage – Leakage shall not exceed the value assumed in the limiting accident analysis (470 GPD).

The OA herein was performed in accordance with the following Surry and industry requirement documents:

- Surry Technical Specifications (TS 6.4.Q)
- Dominion fleet-wide steam generator (SG) program [3.a]
- NEI 97-06 [1]
- EPRI Steam Generator Integrity Assessment Guidelines (IAG) [2.a]
- Dominion SG condition monitoring and operational assessment (CMOA) procedure [3.f]

3.0 OPERATIONAL ASSESSMENT

The following sections summarize the evaluations performed for the degradation mechanisms discussed in Section 2.2.

3.1 Existing SPS2 Degradation Mechanisms

The degradation mechanisms discussed in this section are those which have been previously identified within the Unit 2 SGs.

3.1.1 Circumferential PWSCC within Tubesheet

During a previous outage (EOC26), three circumferential PWSCC indications were identified at tube expansion bulges within the tubesheet in SG C; the first identification of SCC in the Surry Unit 2 SGs. Since that outage all three SGs have been fully examined at least once in the region of interest with array probes. No SCC of any kind has been identified in the Surry Unit 2 SGs since EOC26. No SCC of any kind has been identified in SG B to-date.

The most important parameters in the OA of this degradation mechanism are the beginning of cycle (BOC) degradation severity and degradation growth rate. Conservative analyses are obtained by selecting 95th percentile values for each of these parameters. Using this process, projection of worst case end of cycle (EOC) crack size is accomplished by assuming that the upper bound BOC size is equal to the value which has a probability of detection (POD) of 95%. An upper 95/50 growth rate is then applied, and the resultant EOC crack size is required to exhibit a minimum burst pressure of 3x normal operating pressure differential (NOPD), 4470 psi [3.b]. Burst pressure calculations include consideration of both variations in material properties and uncertainties inherent in the applicable burst pressure equation, such that the evaluation result reflects the 95/50 statistical requirement of Reference [3.b]. If the projected EOC physical degradation is less severe than those dimensions which would lead to a burst pressure of 4470 psi at probability/confidence of 95/50, then operational assessment burst requirements are met. Using the methodology of the EPRI Flaw Handbook [2.b] as incorporated into the EPRI Flaw Handbook Calculator [2.c], the allowable EOC value for this degradation mechanism was found to be 63.3% degraded area (PDA).

The worst case actual BOC size is the largest instance of degradation that is undetected. The actual largest instance of undetected degradation depends upon the detection properties of the inspection method and the actual distribution of degradation sizes. The conservative approach is to set the worst case BOC degradation equal to the depth at 95% POD.

Eddy current signal noise monitoring performed during EOC28 confirmed that the noise levels and POD curve documented in Reference [3.b] are bounding and appropriate for use in this OA. For the OA, it is assumed that an undetected flaw existed in SG B at the beginning of cycle 28 (BOC28) having depth equal to the depth at 95% POD (i.e., 57%TW) and circumferential extent more than twice the maximum extent identified during the EOC26 inspection (i.e., 2 x 99° = 198°, round to 200°). The circumferential extent assumption conservatively bounds all reasonable expectations for length growth during a three cycle operating period. The equivalent percent degraded area (PDA) for this flaw is 31.6 PDA (i.e., 57%TW x 200°/360°).

Although the through-wall growth rate of circumferential cracks identified at Surry during the EOC26 inspection was determined to be zero (Reference [3.c]), growth rate information provided in [2.a] was used to establish a conservative Surry-specific growth rate. For the I600TT plant experiencing the greatest number of SCC indications at the TTS, the largest maximum-depth growth rate was 8.2%TW/EFPY. Adjusting this value to reflect Surry's hot leg temperature of 604°F [3.b] yields a value of 6.9%TW/EFPY. This is used as the 95/50 maximum-depth growth rate. The corresponding average-depth growth rate is 5.5%TW/EFPY (i.e., (6.9)/(1.25)).

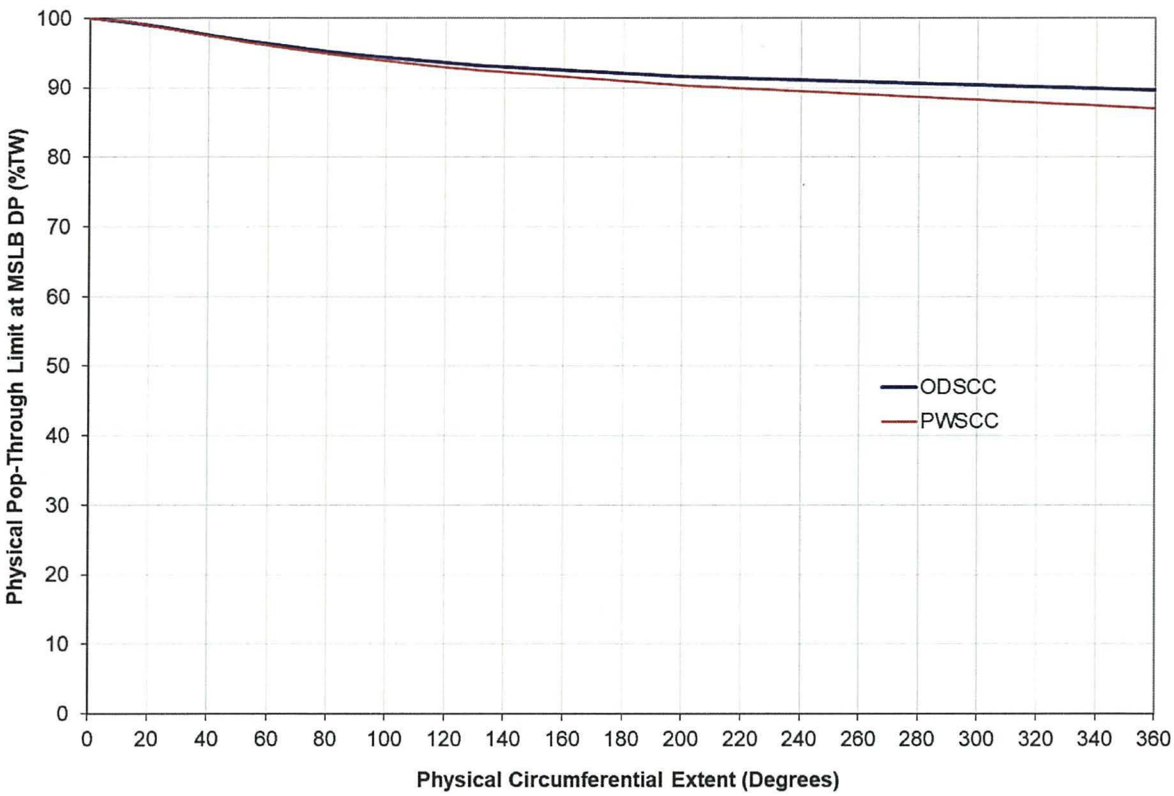
It is assumed that the operating interval for SG B will have a duration of 4.5 EFPY through the next examination in fall 2021 (EOC30); therefore, the 95/50 growth allowance is 24.8%TW (i.e., (4.5)(5.5)). The resulting EOC equivalent crack size is 45.4 PDA (i.e., (57+24.8)(200)/360)). This conservatively projected EOC degradation is comfortably below the EOC allowable limit (63.3 PDA); therefore, structural integrity is demonstrated through EOC30.

Projected leakage integrity at the end of the next cycle depends upon the maximum degradation length and depth. Based on the pop-through relationship described in [2.b], under Surry's limiting accident conditions, pop through and leakage would not occur for a 200° circumferential PWSCC crack with depth less than 90.3%TW (Figure 3-1). The following discussion will demonstrate that this limit will not be exceeded.

As discussed earlier, the worst case BOC crack depth is 57%TW and the 95/50 maximum-depth growth rate throughout the 4.5 EFPY inspection interval is assumed to be 6.9%TW/EFPY. Applying this growth rate to an operating duration of 4.5 EFPY, and adding the growth to the worst case BOC maximum depth yields an EOC worst case maximum depth of 88.1%TW, (i.e., 6.9%TW/EFPY x 4.5 EFPY + 57%TW). This value lies below the 90.3%TW pop-through depth, therefore no leakage from circumferential PWSCC is projected prior to EOC30. Consequently, the accident induced leakage performance criteria will not be violated prior to EOC30 as a result of circumferential PWSCC.

It should be noted that since the preceding evaluation does not credit the strengthening effect of the tubesheet on burst pressure and pop-through depth, the evaluation is very conservative. Realistically, the tubesheet constrains the tube and essentially eliminates the probability of burst and leakage for a flaw of the size evaluated.

Figure 3-1: Pop Through Limit for Circumferential SCC under Accident Conditions



3.1.2 AVB Wear

This evaluation addresses AVB wear relative to tube integrity requirements for a projected operating interval of three cycles for SG B. The SG B AVB wear indications identified during the EOC27 inspection were evaluated in [3.c]. The growth rate used for the operational assessment herein was based on the highest value among the three Unit 2 steam generators at that time: 2.0%TW/EFPY. It is noted that the EOC28 inspection results of SG A and C support the use of a lower growth rate value, but this OA will be based on an assumption of 2.0%TW/EFPY.

The effect of NDE probability of detection must also be considered. The beginning of cycle (BOC) AVB wear depth must be an upper bound estimate of the depth of wear remaining in service immediately following the SG tube inspection. This value must account for the fact that NDE processes have imperfect PODs, and must account for known flaws left in service following the tube inspection. Consistent with [2.a], the limiting BOC AVB wear depth is the adjusted depth of the largest flaw left in service, or the depth at 95% POD, whichever is larger.

Bobbin probe technique ETSS 96041.1 was relied upon during the EOC27 inspection for the detection of AVB wear. For this technique, the depth at 95% POD is conservatively estimated to be 26%TW [3.b, Table 7-3]. The maximum depth of reported AVB wear returned to service in SG B at EOC27 was 17%TW. Adjusting the 17%TW depth to conservatively account for NDE sizing uncertainty at the time of the EOC27 inspection, yields a value of 29.8%TW (3.c). Therefore the limiting BOC28 AVB wear depth was 29.8%TW.

Adjusting the BOC28 depth upward to reflect three fuel cycles of growth (assumed total duration: 4.5 EFPY), yields the EOC30 upper bound depth (UBD):

BOC28 = 29.8%TW	maximum throughwall depth of in-service AVB wear at the beginning of Cycle 28
EOC30 UBD = BOC28 + (4.5 EFPY)(2.0%TW/EFPY)	EOC30 upper bound depth after 4.5 EFPY
EOC30 UBD = 38.8%TW	

The maximum projected EOC30 depth is 38.8%TW which is below the 64%TW structural limit for AVB wear [5]. Therefore, AVB wear is not expected to challenge the structural integrity performance criteria in SG B going forward to the next inspection in EOC30. Since AVB wear is not projected to violate the structural performance criteria prior to the next inspection of SG B, there is reasonable assurance that the accident induced leakage performance criteria will not be exceeded prior to the next inspection of SG B.

3.1.3 Foreign Objects and Foreign Object Wear

The most recent primary side tube inspections performed in each SPS2 SG included array probe examinations of all hot leg and cold leg locations up to the first support structure. This examination provides the best possible foreign object and foreign object wear detection capability. Additionally, sludge lancing and visual inspections were performed at the TTS providing added assurance that no new foreign objects were left in service in a high flow region of the SG (i.e., periphery, no tube lane).

The OA performed following the EOC27 SG B inspection [3.c] concluded that the nine foreign object wear indications reported and returned to service had experienced no ECT signal change during the prior two cycle operating period, and that none of the indications had adjacent foreign objects remaining. The largest flaw, sized 30%TW and 0.24" long, easily satisfied the SIPC depth limit for a 0.24" long flaw (72%TW [3.b]). Since the objects that caused the wear are no longer present at the locations of the wear indications, there is no mechanism to cause future growth. Because the through-wall depths of these flaws were below the plugging limit and satisfied the integrity performance criteria [3.c], and since no growth is expected, there is reasonable assurance that these flaws will continue to meet the performance criteria going forward to EOC30. The same conclusions were reached following the inspection of SGs A and C during EOC28 [3.d].

The potential development of new foreign object wear during the operating period through EOC30 must be considered. It is difficult to predict if and when foreign object wear will occur. However, by examining the aggregate operating history of the Surry Unit 2 SGs with respect to foreign object wear, a judgment of the risk can be developed. During the period between 1992 and 2006, the SGs were often operated for three cycles between inspections. Despite the presence of various foreign objects, no foreign object wear exceeding the performance criteria was detected during that time.

The most recent secondary side visual examinations in each SPS2 SG have involved extensive and disciplined FOSAR activities. Although a large number of short (0.5"), small diameter (0.012") wires consistent with those of a wire brush remain in SG C, these objects do not pose a threat to tube integrity. The wires are very light weight and mobile and are considered to be incapable of causing tube damage. A recommendation was made within [3.d] to further assess these SG C wires during the planned EOC29 secondary side inspections; however, the OA herein concludes that this activity is not required to ensure safe SG operation through EOC30. No objects capable of threatening tube integrity are known to exist in any of the SPS2 SGs. Hence, there is reasonable assurance that existing foreign material will not cause the SG structural and leakage integrity performance criteria to be exceeded throughout the period preceding EOC30.

Based on Surry and industry operating experience, new foreign material introduced during this operating period is unlikely to cause structurally significant tube degradation. However, in the event of such an occurrence, primary to secondary leakage monitoring procedures in place at Surry provide a high degree of confidence of safe unit shutdown without challenging the SIPC or AILPC.

3.1.4 TSP/FDB Wear

No TSP/FDB wear was identified in SG B during EOC27. Of the seven indications identified during EOC28 in SGs A and C, only one exhibited any evidence of growth (2.49 %TW/EFPY) [3.e]. For the purpose of this SG B OA, a growth rate of 5%TW/EFPY will be assumed and applied from EOC27 through EOC30 for an assumed duration of 4.5 EFPY. The total growth allowance for hypothetical TSP/FDB wear is therefore 22.5%TW (i.e., (4.5)(5)).

Since there are no known TSP/FDB wear flaws in SG B, the BOC28 depth is based on the bobbin probe POD. Bobbin probe technique ETSS 96004.1 was relied upon during the EOC27 inspection for the detection of TSP/FDB wear. For this technique, the depth at 95% POD is conservatively estimated to be 19%TW [3.b, Table 7-3]; therefore the limiting BOC28 TSP/FDB wear depth is assumed to be 19%TW.

Adjusting the BOC28 depth upward to reflect three fuel cycles of growth (22.5%TW), yields an EOC30 upper bound depth value of 41.5%TW (i.e., (19)+(22.5)). The projected upper bound depth at EOC30 is 41.5%TW which is below the 56.6%TW structural limit for TSP/FDB wear [5]. Therefore, TSP/FDB wear is not expected to challenge the structural integrity performance criteria in SG B during the period preceding the next inspection in EOC30. Since TSP/FDB wear is not projected to violate the structural performance criteria prior to the next inspection of SG B, there is reasonable assurance that TSP/FDB wear will not cause the accident induced leakage performance criteria to be exceeded prior to the next inspection of SG B.

3.1.5 Pitting

Although minor tube pitting was identified in the Unit 2 SGs during the 1990s, no evidence of an active pitting degradation mechanism has been identified since chemical cleaning was performed in 1994. All tubes with pit indications (12 tubes) were removed from service during prior outages. Due to the demonstrated dormancy of this mechanism there is reasonable assurance that pitting will not violate the structural or leakage performance criteria in SG B through EOC30.

3.2 Important Potential Degradation Mechanisms

3.2.1 Circumferential ODSCC at Top-of-Tubesheet

Although no circumferential ODSCC has been identified in the Unit 2 SGs, during a previous Unit 1 outage one circumferential ODSCC indication was identified, and this experience is used as the basis of an analysis of hypothetical circumferential ODSCC in Unit 2 SG B.

The most important parameters in the OA of this degradation mechanism are the beginning of cycle degradation severity and degradation growth rate. Conservative analyses are obtained by selecting 95th percentile values for each of these parameters. Using this process, projection of worst case end of cycle crack size is accomplished by assuming that the upper bound BOC size is equal to the value which has a POD of 95%. An upper 95/50 growth rate is then applied. The resultant EOC crack size is required to exhibit a minimum burst pressure of 3xNOPD, 4470 psi [3.b].

Burst pressure calculations include consideration of variations in material properties and uncertainties inherent in the applicable burst pressure equation, such that the evaluation result reflects the 95/50 statistical requirement of [2.a]. If the projected EOC physical degradation is less severe than those dimensions which would lead to a burst pressure of 4470 psi at probability/confidence of 95/50 then operational assessment strength requirements are met. Using the methodology of the EPRI Flaw Handbook [2.b] as incorporated into the EPRI Flaw Handbook Calculator [2.c], the allowable EOC value for this degradation mechanism was found to be 74.6% degraded area (PDA).

The worst case actual BOC size is the largest instance of degradation that is undetected. The actual largest instance of undetected degradation depends upon the detection properties of the inspection method and the actual distribution of degradation sizes. The conservative approach is to set the worst case BOC degradation equal to the depth at 95% POD. During the EOC27 inspection of SG B, susceptible locations (100% top of tubesheet) were examined with array probes and array ETSS 20400.1 was relied upon for detection of circumferential ODSCC (no circumferential ODSCC was identified).

During the qualification work for ETSS 20400.1 the array probe successfully detected all circumferential ODSCC having maximum depth of 42%TW and greater. Therefore, 42%TW represents a conservative estimate of the worst case maximum depth of circumferential ODSCC that may have remained undetected during EOC27. Note that the POD developed for Surry based on noise monitoring and MAPOD analyses is less limiting than this assumed performance [3.e].

The indication observed at SPS1 measured 73° circumferentially. In the absence of additional dimensional data for SPS2 cracks, a bounding extent of 200° is assumed for the purpose of this evaluation. Conservatively assuming that the maximum crack depth of 42%TW occurs over the entire 200° circumferential extent yields an equivalent crack size at the BOC of 23.3 PDA (i.e., (42)(200)/(360)).

Because only one indication of this type has been identified at Surry (Unit 1), growth rate information provided in [2.a] was used to establish a Surry-specific growth rate. For the I600TT plant experiencing the greatest number of SCC indications at the TTS, the largest maximum-depth growth rate was 8.2%TW/EFPY. Adjusting this value to reflect Surry's hot leg temperature of 604°F [3.b] yields a value of 6.9%TW/EFPY. This is used as the 95/50 maximum-depth growth rate. The corresponding average-depth growth rate is 5.5%TW/EFPY (i.e., (6.9)/(1.25)).

It is assumed that the operating interval for SG B will have a duration of 4.5 EFPY through the next examination in fall 2021 (EOC30); therefore, the 95/50 growth allowance is 24.8%TW (i.e., (4.5)(5.5)). The resulting EOC equivalent crack size is 37.1 PDA (i.e., (42+24.8)(200)/360)). This conservatively projected EOC degradation is comfortably below the EOC allowable limit (74.6 PDA); therefore, structural integrity is demonstrated through EOC30.

Projected accident induce leakage integrity at the end of the next cycle depends upon the maximum degradation length and depth. Based on the pop-through relationship described in [2.b], under Surry's limiting accident conditions, pop-through and leakage would not occur for a 200° circumferential crack with depth less than 91.6%TW (Figure 3-1). The following discussion will demonstrate that this limit will not be exceeded.

As discussed earlier, the worst case BOC crack depth is 42%TW and the 95/50 maximum-depth growth rate throughout the 4.5 EFPY inspection interval is assumed to be 6.9%TW/EFPY. Applying this growth rate to an operating duration of 4.5 EFPY, and adding the growth to the worst case BOC maximum depth yields an EOC worst case maximum depth of 73.1%TW, (i.e., 6.9%TW/EFPY x 4.5 EFPY + 42%TW). This value lies below the 91.6%TW pop-through depth, therefore no leakage from circumferential ODSCC is projected prior to EOC30. Consequently, the accident induced leakage performance criteria will not be violated prior to EOC30 as a result of circumferential ODSCC.

3.2.2 Axial ODSCC at Tube Support Plates

Although no indications of axial ODSCC have been identified in either Surry unit at any location, hypothetical axial ODSCC at tube support plates (TSPs) is evaluated in this section. This degradation mechanism is considered to be bounding of axial stress corrosion cracking at other locations for three reasons. First, ECT bobbin probe examination methods are relied upon to detect this mechanism in non-high stress tubes. The bobbin probe POD is less favorable than that of the +point or array probes which are used at the top of tubesheet and other discrete areas of interest. Second, the crack length utilized in this analysis corresponds to the full thickness of the TSP (1.12") which bounds the lengths of cracks typically identified in other locations of the SG. Third, the elevated residual hoop stress associated with the high stress tubes may result in higher crack depth growth rates.

During EOC27, Surry examined the hot leg TSPs in the two SG B high stress tubes using an array probe. However, this evaluation conservatively assumes that the EOC27 examination relied entirely on the bobbin probe to detect axial ODSCC at all SG B TSPs, including the two known and any unknown high stress tubes. In addition, the higher crack growth rates applicable to the evaluation of high stress tubes are conservatively applied within the simulation to all TSP axial ODSCC even though there are only two high stress tubes in SG B.

Following the methodology described in [2.a], a fully probabilistic multi-cycle OA analysis was performed. Framatome software (MultiFram [4.b]), simulates the life-cycle of a susceptible tube population and generates Monte Carlo projections of both detected and undetected flaws for multiple cycles of operation. The simulation considers inspection POD, new flaw initiation, and growth to calculate burst probability and accident-induced leakage at time points of interest.

The POD curve describing bobbin probe detection of axial ODSCC at TSPs that was used in this evaluation is shown in Figure 3-2. This POD curve was developed using Surry Unit 2 SG B ECT noise measurements in conjunction with the MAPOD methodology described in [2.e].

For this evaluation the simulation of axial ODSCC at SG B TSPs was benchmarked to cause axial ODSCC detection during EOC27, when in fact no ODSCC was detected during this or any other outage. This approach ensures that the crack initiation function utilized in the analysis is conservative.

The depth growth rate distribution utilized in this evaluation was developed by adjusting the upper bound growth rates of [2.a] to reflect the lower hot leg operating temperature at Surry. The resulting distribution is shown in Figure 3-3.

The distribution of EOC30 worst-case degraded tube burst pressures resulting from this analysis is shown in Figure 3-4. This figure demonstrates that the 5th percentile burst pressure, 5546 psi (i.e., the lower 95/50 burst pressure) satisfies the SIPC limit of 4,470 psi; therefore, it is concluded that axial ODSCC at TSPs will not cause the structural integrity performance criteria to be exceeded in SG B prior to EOC30.

The total upper 95/50 leakage resulting from the simulation is zero; therefore it is concluded that axial ODSCC at TSPs will not cause the accident-induced leakage performance criteria to be exceeded prior to EOC30.

Figure 3-2: Unit 2 SG B Bobbin Probe POD for Axial ODSCC @TSPs

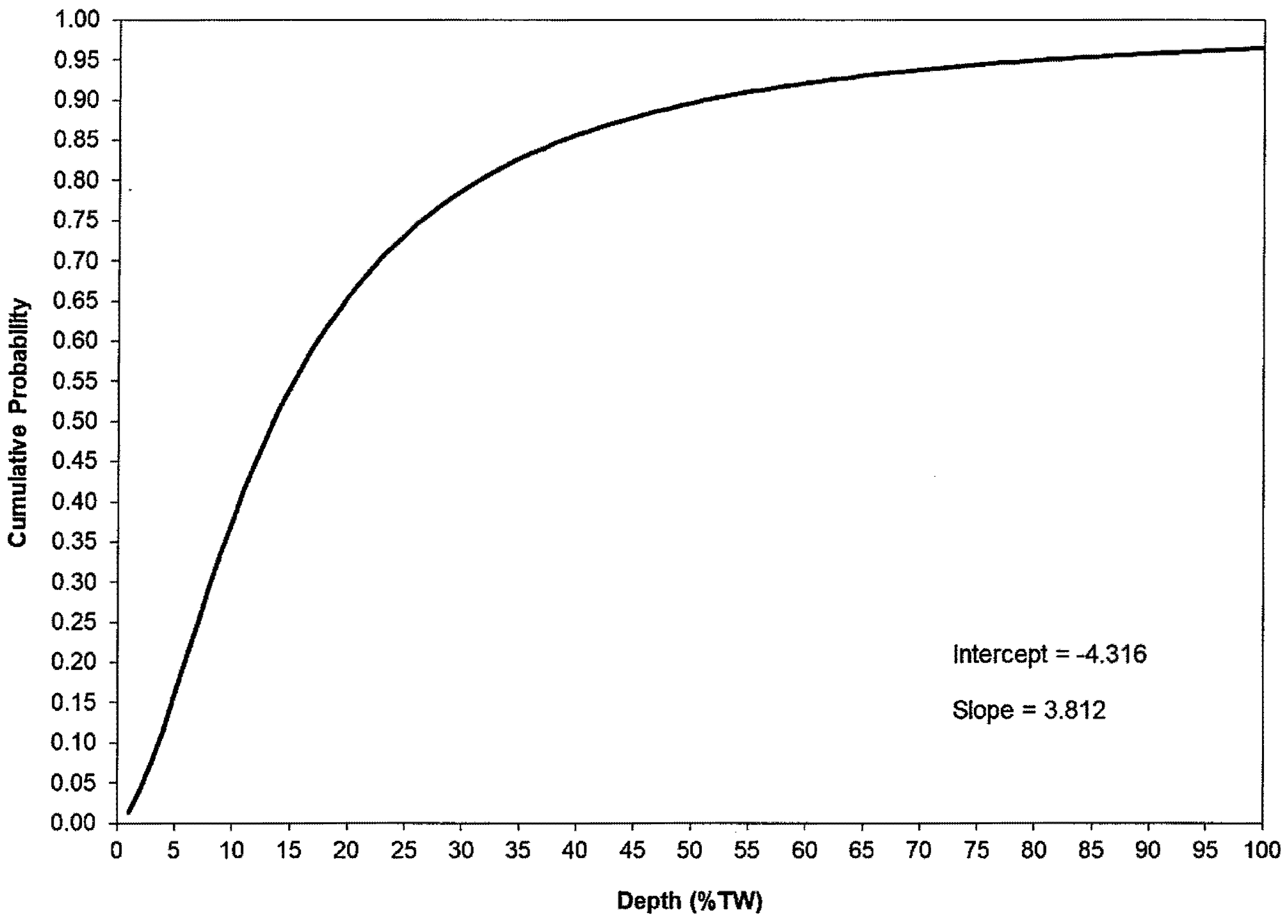


Figure 3-3: Growth Rate – Axial ODSCC @TSPs

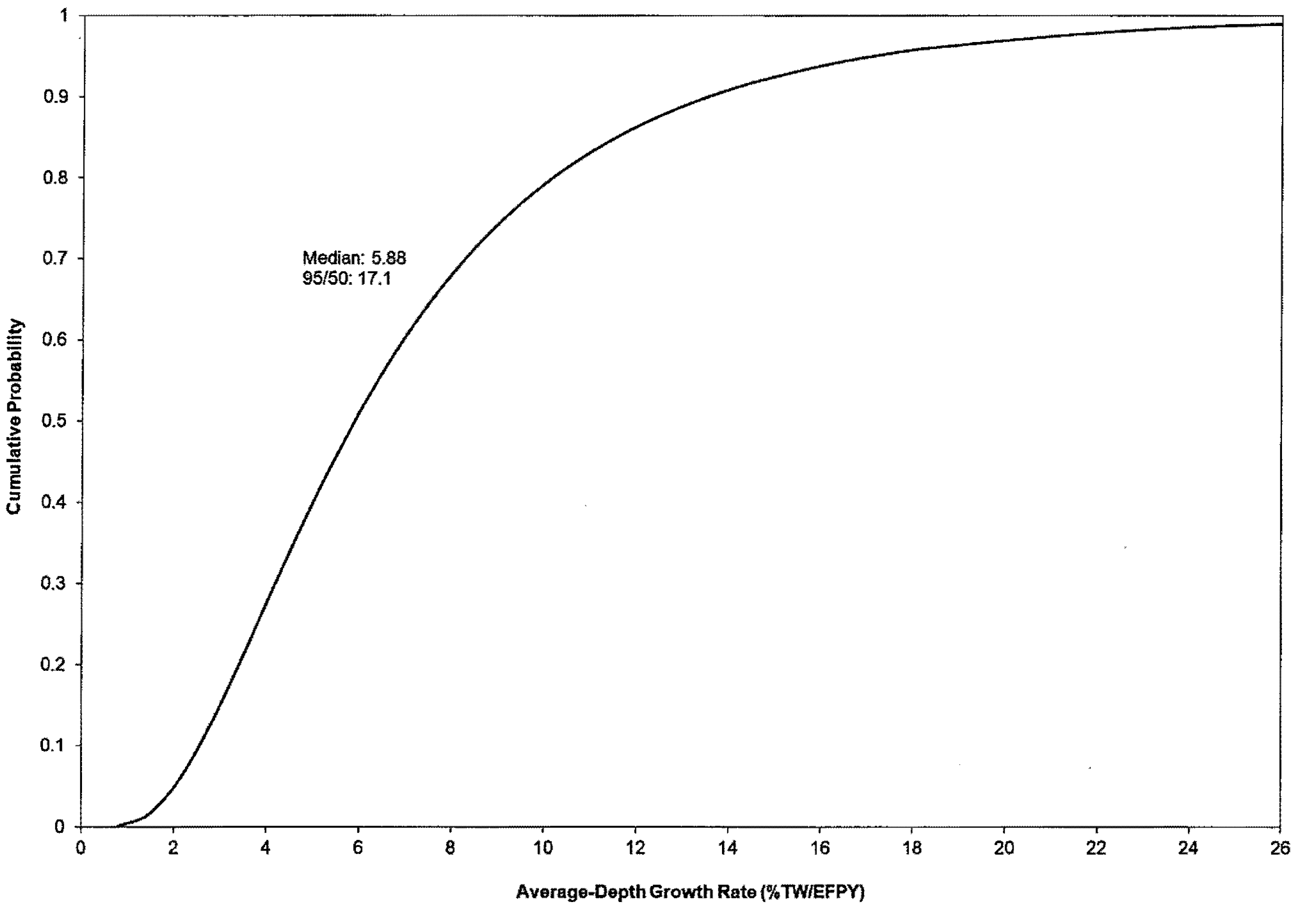
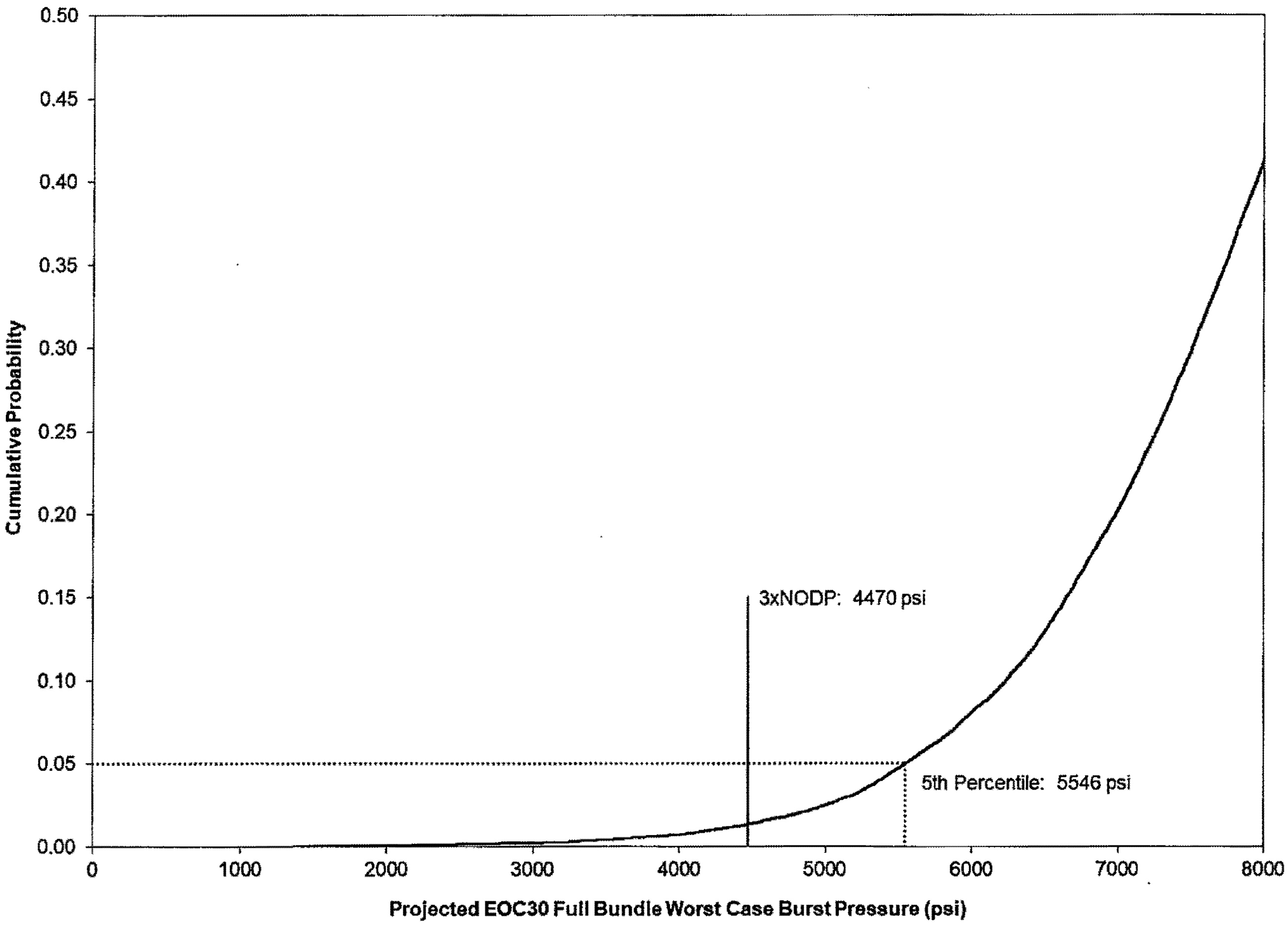


Figure 3-4: EOC30 Limiting Burst Pressure – Axial ODSCC @TSPs



3.2.3 Axial PWSCC at Top-of-Tubesheet

Although no indications of axial PWSCC have been identified in the Unit 2 SGs, one axial PWSCC indication was identified in Unit 1 at the hot leg top of tubesheet (TTS) during the 2009 Unit 1 outage (none have been identified since). This OA evaluates the potential impact of hypothetical TTS axial PWSCC in Unit 2 SG B going forward to EOC30.

The same fully probabilistic methodology that was described in Section 3.2.2 was used to project future burst probability and accident-induced leakage for axial PWSCC at the TTS. The key inputs are inspection POD, new flaw initiation function, and growth rate probability distribution.

Historically, the tubesheet region of Unit 2 SGs has been extensively examined with techniques capable of detecting SCC. In SG B, all of the hot leg and cold leg tubesheet regions were examined with array probes during EOC25 (2014) and EOC27 (2017). The applicable Surry-specific POD curve describing array probe detection of TTS axial PWSCC is shown in Figure 3-5. This POD curve was developed using Surry ECT noise measurements in conjunction with the MAPOD methodology described in [2.e].

In order to ensure that the crack initiation function used was conservative, the simulation was benchmarked to cause axial PWSCC to be detected during EOC27, when in fact no PWSCC was detected. The depth growth rate distribution utilized in this evaluation was based on the typical growth rate distribution of [2.a] adjusted to Surry's hot leg temperature (Figure 3-6). The crack length was set to a value of 0.75" which is bounding for axial SCC at the TTS.

The distribution of EOC30 worst-case degraded tube burst pressures resulting from this analysis is shown in Figure 3-7. This figure demonstrates that the 5^{th} percentile burst pressure, 5342 psi (i.e., the lower 95/50 burst pressure) satisfies the SIPC limit of 4,470 psi; therefore, it is concluded that TTS axial PWSCC will not cause the structural integrity performance criteria to be exceeded in SG B prior to EOC30.

The projected upper 95^{th} percentile leak rate under MSLB conditions is zero; therefore, it is concluded that TTS axial PWSCC will not cause the accident-induced leakage performance criteria to be exceeded prior to EOC30.

Figure 3-5: Array Probe POD for Axial PWSCC @TTS

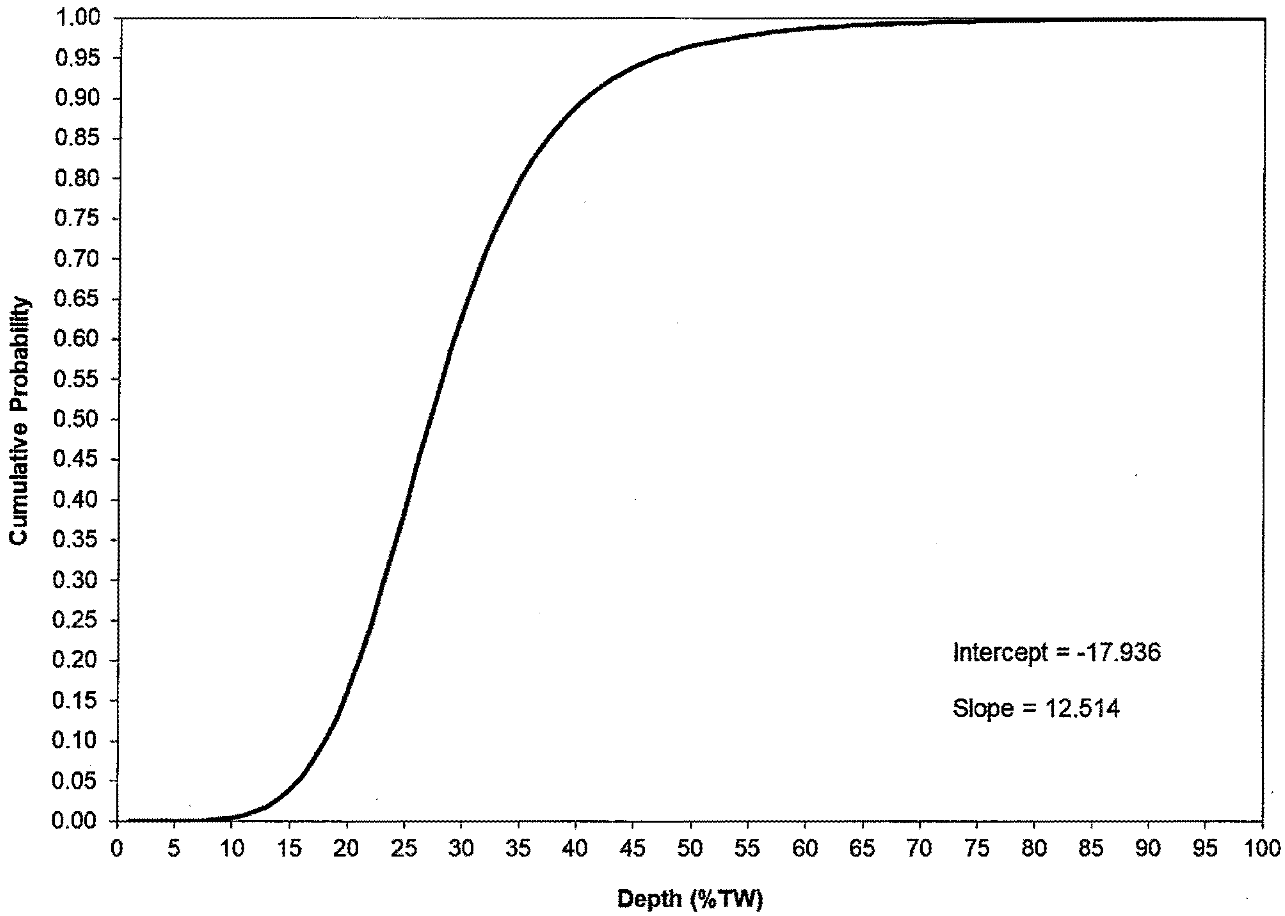


Figure 3-6: Growth Rate – Axial PWSCC @TTS

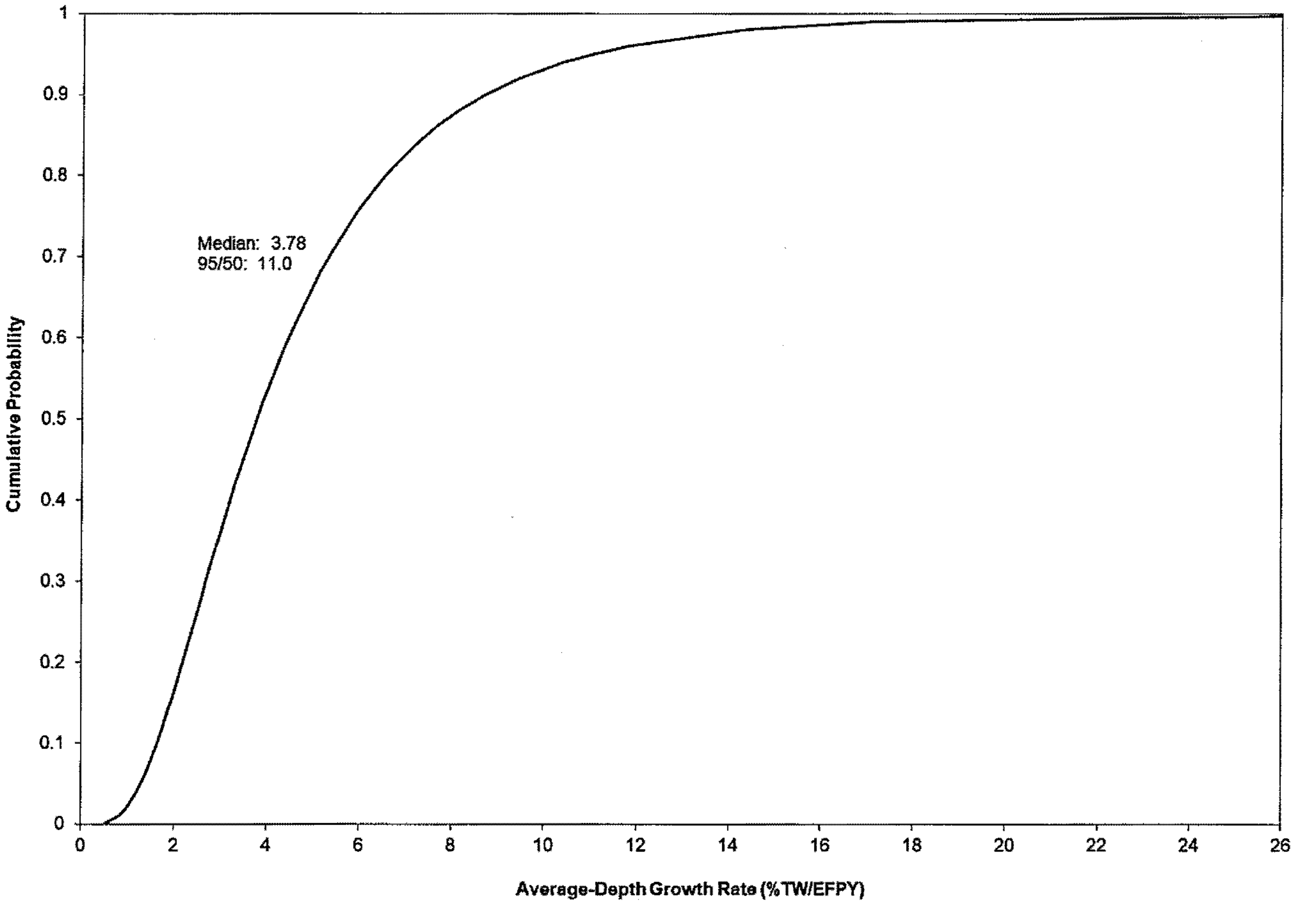
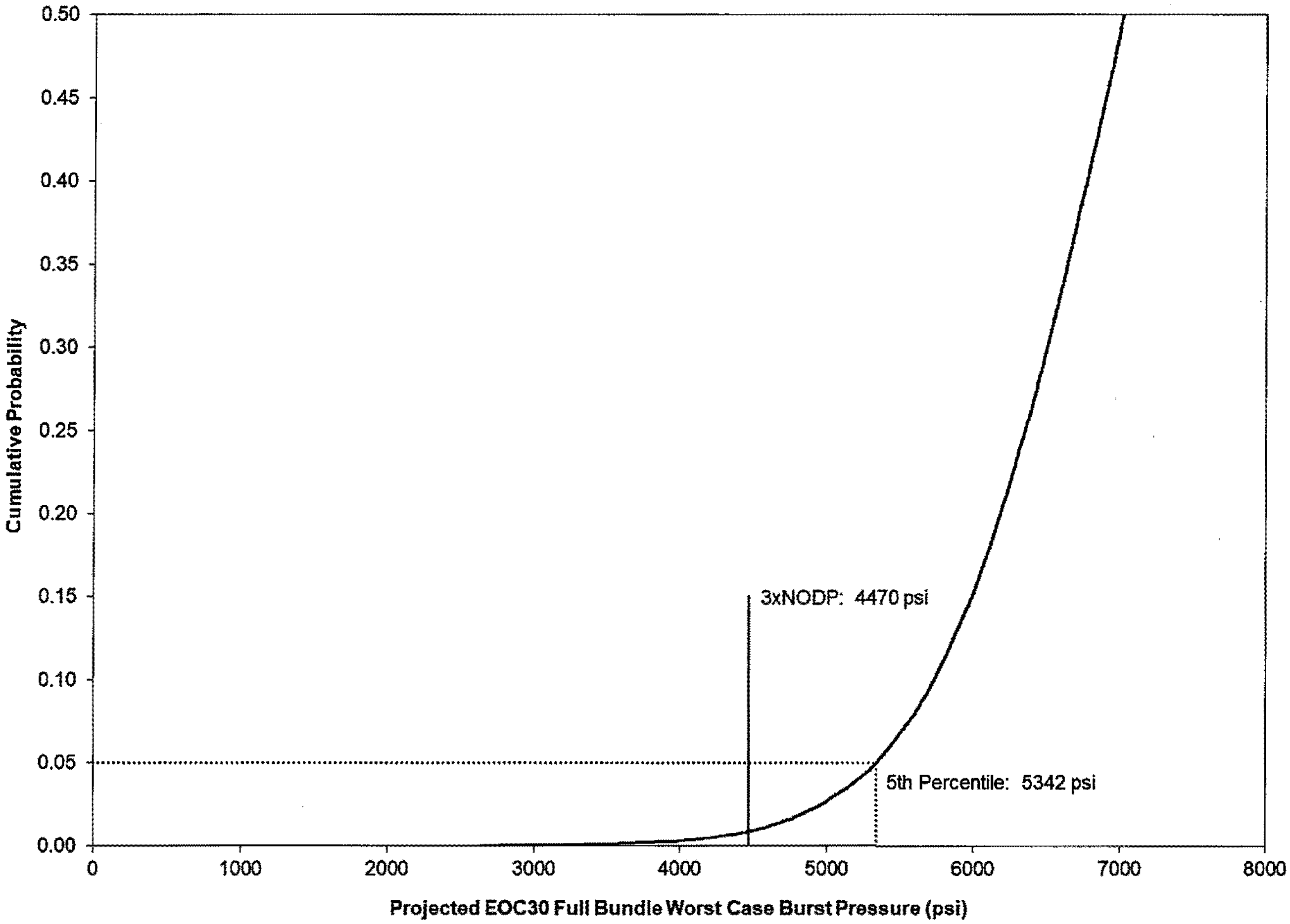


Figure 3-7: EOC30 Limiting Burst Pressure – Axial PWSCC @TTS



3.3 Secondary Side Internals

The new stainless steel feedrings installed in all three SGs during EOC23 remediated the FAC which had occurred at the j-nozzle interfaces and at other locations within the feedring. The new feedrings that were fabricated of FAC-resistant material have not experienced FAC, and are not expected to experience FAC in the future. The secondary side visual examinations performed in each SG have revealed no degradation that could threaten SG tube integrity; therefore, there is reasonable assurance that tube integrity will not be threatened by secondary side degradation throughout the period preceding EOC30.

3.4 Projected Accident Leakage

Since none of the evaluated wear degradation mechanisms are projected to violate the structural performance criteria prior to the next scheduled primary inspection of SG B, there is reasonable assurance that the AILPC will not be exceeded prior to EOC30. Similarly, the evaluation of each postulated corrosion mechanism demonstrated that there is reasonable assurance that the AILPC will not be exceeded by these mechanisms prior to EOC30.

The PARC requires that the difference between the allowable accident induced leakage level (470 GPD) and the accident induced leakage from sources other than the tubesheet expansion region, be divided by 1.8 and compared to the observed operational leakage. The PARC requires an administrative operational leakage limit to be established such that this calculated value is not exceeded.

One potential source of other postulated accident leakage is leakage through installed plugs. This is considered very unlikely to occur and if it did occur would result in negligible leakage. Another potential source is leakage through undetected or newly initiated SG tube corrosion. However, on the basis of the most recent inspections of each SPS2 SG in which no corrosion indications were identified, and on the operational assessment herein of potential corrosion mechanisms, there is reasonable assurance that no such leakage will occur during the period preceding EOC30.

It is therefore concluded that there are no other identified sources of potential leakage applicable to the calculation of an administrative limit for the next operating cycle. Consequently, the appropriate administrative limit would be 261 GPD (i.e., (470 – 0) / 1.8). Since this value is less limiting than the current technical specification limit of 150 GPD, the current technical specification limit remains appropriate.

3.5 Operational Leakage

In the absence of degradation projected to exceed the AILPC during the next operating period, there is reasonable assurance that normal operating conditions will not lead to a violation of the operational leakage performance criteria. Although there are no known conditions of concern, sensitivity to primary-to-secondary leakage events will continue under Surry's conservative monitoring procedures.

3.6 Operational Assessment Conclusion

There is reasonable assurance that the structural integrity and leakage performance criteria will remain satisfied in SG B throughout the period preceding EOC30, for a total operating duration of three cycles between primary side inspections. Table 3-1 summarizes the projected margin to SIPC and AILPC at EOC30 for each evaluated mechanism.

Table 3-1: SG B Integrity Margin Summary

Degradation Mechanism	SIPC		AILPC	
	Limit	EOC30 Projection	Limit	EOC30 Projection
Circumferential PWSCC within the tubesheet expansion[1]	64 PDA	45.4 PDA	90.3 %TW Pop-Through Depth	88 %TW Maximum Depth
AVB wear	64 %TW	38.8 %TW Maximum Depth	470 GPD	Zero Leakage
Foreign object wear	72 %TW	30 %TW Maximum Depth	470 GPD	Zero Leakage
TSP/FDB wear	56.6 %TW	41.5 %TW Maximum Depth	470 GPD	Zero Leakage
Pitting	Dormant. No projected pitting.			
Circumferential ODSCC @TTS	74.6 PDA	37.1 PDA	91.6 %TW Pop-Through Depth	73.1 %TW Maximum Depth
Axial PWSCC @TTS	4470 psi[2]	5546 psi	470 GPD	Zero Leakage
Axial ODSCC @TSPs	4470 psi[2]	5342 psi	470 GPD	Zero Leakage

[1] The beneficial presence of the tubesheet is not credited in the evaluation

[2] Minimum acceptable burst pressure

4.0 REFERENCES

1. NEI 97-06, "Steam Generator Program Guidelines," Rev. 3, March 2011
2. EPRI Documents
   a. EPRI Report 3002007571, "SG Integrity Assessment Guidelines, Revision 4," June 2016
   b. EPRI Report 3002005426, "SG Degradation Specific Management Flaw Handbook, Revision 2," October 2015
   c. EPRI Report 3002003048, "Steam Generator Management Program: Flaw Handbook Calculator (SGFHC) for Excel 2010 v1.0," June 2014
   d. EPRI Report 3002000475, "SGMP: PWR Generic Tube Degradation Predictions," December 2013
   e. EPRI Report 3002010334, "Model Assisted Probability of Detection Using R (MAPOD-R), Version 2.1," September 2017
3. Dominion Documents
   a. Dominion Fleet Administrative Procedure ER-AA-SGP-101, "Steam Generator Program," Rev. 0
   b. Dominion ETE-CEP-2020-1002, "Steam Generator Degradation Assessment Surry Unit 2 Refueling Outage 2R29," Revision 0, April 2020
   c. Dominion ETE-SU-2017-0017, "Steam Generator Condition Monitoring and Operational Assessment Surry Unit 2 Spring 2017," Revision 0, May 2017 (EOC27)
   d. Dominion ETE-SU-2018-0043, "Steam Generator Condition Monitoring and Operational Assessment Surry Unit 2 RFO 2R28," Revision 0, November 2018
   e. Dominion Document ETE-CEP-2019-1006, "Steam Generator Condition Monitoring and Operational Assessment Surry Unit 1 October 2019 Refueling Outage EOC29/REOC24," Revision 0, November 2019
   f. Dominion Fleet Administrative Procedure ER-AA-SGP-103, "Steam Generator Condition Monitoring and Operational Assessments," Revision 0
   g. VEPCO Document Serial No. 17-415, "VEPCO Surry Power Station Unit 2 SG Tube Inspection Report for the Spring 2017 Refueling Outage," October 26, 2017
   h. VEPCO Document Serial No. 19-153, "VEPCO Surry Power Station Unit 2 SG Tube Inspection Report for the Fall 2018 Refueling Outage," May 16, 2019
4. Framatome Documents
   a. Framatome Document 51-5054387-00, "Residual Stress Screening of Long Row SG Tubes in Surry Units 1 and 2," December 2004

b. Framatome Document 32-9038747-000, "Validation of Multi-Cycle Probabilistic Integrity Assessment Software – Multifram," May 2007

5. Westinghouse WCAP-16095-P, Revision 2, "Regulatory Guide 1.121 Analysis for the Surry Units 1 and 2 SGs and Structural Integrity Performance Criterion Application for 2609 MWt NSSS Power," April 2009

5.0 ABBREVIATIONS AND ACRONYMS

AILPC	Accident Induced Leakage Performance Criteria
ARC	Alternate Repair Criteria
AVB	Anti-Vibration Bar
BET	Bottom of Expansion Transition
BLG	Bulge
BOC	Beginning Of Cycle
BPC	Baffle Plate Cold
BPH	Baffle Plate Hot
CDS	Computer Data Screening
CM	Condition Monitoring Assessment
CMOA	Condition Monitoring and Operational Assessment
DA	Degradation Assessment
DDH	Distorted Dent w/Indication
DDI	Distorted Dent w/Indication
DDS	Distorted Dent w/Indication
DMT	Deposit Minimization Treatment
DNT	Dent
ECT	Eddy Current Test
EFPY	Effective Full Power Years
EOC	End Of Cycle
ETSS	Examination Technique Specification Sheet
FAC	Flow Assisted Corrosion
FDB	Flow Distribution Baffle
FK	Foreign Object Tracking System Key
FOSAR	Foreign Object Search And Retrieval
FOTS	Foreign Object Tracking System
GPD	Gallons Per Day
HRS	High Residual Stress
INF	Indication Not Found
INR	Indication Not Reportable
LGV	Local Geometry Variation
LPM	Loose Part Monitoring
LPS	Loose Part Signal
MAA	Multiple Axial Anomaly
MBH	Manufacturing Burnish Mark
NDF	No Degradation Found
NOPD	Normal Operating Pressure Differential
NTE	No Tube Expansion
OA	Operational Assessment
ODSCC	Outer Diameter Stress Corrosion Cracking
OVR	Over Roll
OXP	Over Expansion
PARC	Permanent Alternate Repair Criteria
PDA	Percent Degraded Area
PIT	Pit
PLP	Possible Loose Part
POD	Probability Of Detection
PTE	Partial Tube Expansion
PVN	Permeability Variation
PWSCC	Primary Water Stress Corrosion Cracking
QDA	Qualified Data Analyst
REOC	Replacement End Of Cycle
RPC	Rotating Pancake Coil (generic term for all rotating probes)
SAA	Single Axial Anomaly
SCC	Stress Corrosion Cracking
SG	Steam Generator
SIPC	Structural Integrity Performance Criteria
SSI	Secondary Side Inspection
TSC	Tube Sheet Cold
TSH	Tube Sheet Hot
TSP	Tube Support Plate
TTS	Top of Tubesheet
TW	Through Wall
VOL	Volumetric

Enclosure 2

MARKED-UP TECHNICAL SPECIFICATION PAGE

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

b. After the first refueling outage following SG installation, inspect each SG at least every 48 effective full power months or at least every other refueling outage (whichever results in more frequent inspections).* In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as defined in b.1, b.2, and b.3 below. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be inspected in the inspection period after the determination that a new form of degradation could potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period. Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period begins at the conclusion of the included SG inspection outage.

1. After the first refueling outage following SG installation, inspect 100% of the tubes during the next 120 effective full power months. This constitutes the first inspection period;

2. During the next 96 effective full power months, inspect 100% of the tubes. This constitutes the second inspection period; and

3. During the remaining life of the SGs, inspect 100% of the tubes every 72 effective full power months. This constitutes the third and subsequent inspection periods.

* As approved by Amendment Nos. XXX and XXX, the inspection of Surry Unit 2 SG B may be deferred, on a one-time basis, from the Surry Unit 2 spring 2020 refueling outage (S2R29) to the Surry Unit 2 2021 fall refueling outage (S2R30).

Enclosure 3

PROPOSED TECHNICAL SPECIFICATION PAGE

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

b. After the first refueling outage following SG installation, inspect each SG at least every 48 effective full power months or at least every other refueling outage (whichever results in more frequent inspections).* In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as defined in b.1, b.2, and b.3 below. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be inspected in the inspection period after the determination that a new form of degradation could potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period. Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period begins at the conclusion of the included SG inspection outage.

1. After the first refueling outage following SG installation, inspect 100% of the tubes during the next 120 effective full power months. This constitutes the first inspection period;

2. During the next 96 effective full power months, inspect 100% of the tubes. This constitutes the second inspection period; and

3. During the remaining life of the SGs, inspect 100% of the tubes every 72 effective full power months. This constitutes the third and subsequent inspection periods.

* As approved by Amendment Nos. XXX and XXX, the inspection of Surry Unit 2 SG B may be deferred, on a one-time basis, from the Surry Unit 2 spring 2020 refueling outage (S2R29) to the Surry Unit 2 2020 fall refueling outage (S2R30).