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CP-20200276
TXX-20032

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

Ref 10 CFR 50.90
10 CFR 50.91(b)(1)

04/14/2020

SUBJECT: COMANCHE PEAK NUCLEAR POWER PLANT
DOCKET NOS. 50-445 AND 50-446
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION REGARDING EXIGENT LICENSE AMENDMENT 20-003 REVISION TO TECHNICAL SPECIFICATION 5.5.9, "UNIT 1 MODEL D76 AND UNIT 2 MODEL D5 STEAM GENERATOR (SG) PROGRAM"

Reference 1. Letter TXX-20025 from Thomas P. McCool to the NRC "Exigent License Amendment Request (LAR) 20-003 Revision to Technical Specification (TS) 5.5.9, 'Unit 1 Model D76 and Unit 2 Model D5 Steam Generator (SG) Program'" (ML 20101M879)

2. NRC email from Dennis Galvin to Jack Hicks, "Request for Additional Information License Amendment Request for One Time Change to Technical Specification 5.5.9 'Unit 1 Model D76 and Unit 2 Model D5 Steam Generator (SG) Program'" dated April 13, 2020

Dear Sir or Madam:

Vistra Operations Company LLC ("Vistra OpCo") hereby submits a response to the NRC request for additional information (RAI) (Reference 2) regarding the Steam Generator Program technical specification License Amendment Request (LAR) submitted with Reference 1. The attachments to this letter provide Vistra OpCo's response to the NRC RAI.

This communication contains no new commitments.

Should you have any questions, please contact James Barnette at (254) 897-5866 or james.barnette@luminant.com.

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

Executed on 04/14/2020.

Sincerely,

Steven K. Sewell

Attachments:

1 Response to Request for Additional Information Regarding Exigent License Amendment 20-003 Revision to Technical Specification 5.5.9, "Unit 1 Model D76 and Unit 2 Model D5 Steam Generator Program"

2 Marked-up Copy of CPNPP TS 5.5.9

c - Scott Morris, Region IV [Scott.Morris@nrc.gov]
Dennis Galvin, NRR [Dennis.Galvin@nrc.gov]
John Ellegood, Senior Resident Inspector, CPNPP [John.Ellegood@nrc.gov]
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Attachment 1 to TXX-20032

COMANCHE PEAK NUCLEAR POWER PLANT

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION REGARDING EXIGENT LICENSE AMENDMENT 20-003 REVISION TO TECHNICAL SPECIFICATION 5.5.9, "UNIT 1 MODEL D76 AND UNIT 2 MODEL D5 STEAM GENERATOR PROGRAM"

The NRC Staff's request for additional information (RAI) is provided below in bold text and is followed by the Vistra OpCo responses.

CPNPP-RAI-1:
Attachment 2, page 41/57 discusses axial outer diameter stress corrosion cracking (ODSCC) at tube support plates (TSPs) for high stress tubes. The attachment states "For this evaluation, the length form factor is based on a uniform distribution from 1 to 3." Please clarify the basis for these distribution values.

Response:

Form factors are an input to the Westinghouse fully probabilistic software when evaluating axial ODSCC flaws in high stress tubes at tube support plate locations. Since the probability of detection (POD) and growth inputs are defined in terms of maximum depth, and the length input is defined in terms of total length, shape factors are applied to convert the individual flaw parameters to terms of structural equivalent depth and structural equivalent length for compatibility with the burst regression. For the Comanche Peak Unit 2 deferral OA for axial ODSCC at TSP, which is a potential mechanism, a length form factor with a uniform distribution from 1 to 3 was applied. The form factor is developed based on pulled tube data from the axial ODSCC ETSS Techniques I28411, I28412 and I28413. ETSS I28413 is the bobbin technique applied for detection of axial ODSCC at Comanche Peak Unit 2. Compilation of the data shows that the ratio of total length to structural equivalent length ranges from 1.0 to about 6.0 and can be reasonably described as a uniform distribution over the range of ratios between 1.0 and 4.0. For flaws less than 0.4 inch the average length ratio is 1.3 with an upper bound of 2.5, whereas for flaws greater than or equal to 0.4 inch the average length ratio is 1.8 with an upper bound value of 3.6.

For the Comanche Peak Unit 2 axial ODSCC potential mechanism evaluation an upper bound of 3.0 was applied. This distribution was considered appropriate since the mean flaw length is approximately 0.53 inch and thus captured effects of the average length for both flaws shorter than the mean and flaws longer than the mean. For all iterations of the probabilistic calculation, the developed end-of-cycle (EOC) maximum depths and total flaw lengths are converted to structural equivalent depths and structural equivalent lengths by sampling from the form factor distribution, which in the case of structural equivalent length is a uniform distribution from 1.0 to 3.0.

It is noted that if an additional measure of conservatism is applied to adjust the form factor length distribution to have an upper bound of 2.5, the probability of burst (POB) and probability of leakage (POL) both remain below 1.0% with no predicted leakage at the 95th percentile given other inputs in the axial ODSCC TSP potential mechanism OA remain the same.

CPNPP-RAI-2:
Page 52/57 in Attachment 2 describes Comanche Peak's efforts to identify high stress tubes. It is known that the original screening for high stress tubes performed circa 2003 did not identify all the high stress tubes at some other plants. Subsequent to 2003, additional information was provided concerning screening for high stress tubes. One plant currently seeking an Exigent LAR related to SG inspection did a screening as late as 2017 that identified some additional high stress ("signature") tubes.

a. Please elaborate on the discussion provided on Page 52/57 regarding the screening performed for high stress tubes and why you are confident that all high stress tubes have been identified.
b. The operational assessment analysis (OA) analysis for potential high stress tubes cracking at TSPs uses an enhanced probability of detection (POD) from a combined bobbin coil inspection supplemented by +Point inspection. Assuming that a high stress tube was not identified, and was therefore only examined with a bobbin probe, how many effective full power years (EFPY) ago could a TSP crack have initiated and still meet the performance criteria at 2RF19.

Response:

Response 2.a.

Westinghouse is confident that the Comanche Peak Unit 2 high stress tubes have been identified. High stress tubes fall into two categories:

1. "Signature" tubes that are among the low-row tubes. Those tubes in Rows 1-9 that received a final stress relief after forming the U-bends, and
2. "Two-sigma" tubes. Those tubes in rows greater than Row 9 which did not receive a stress relief after forming the U-bend.

The tube fabrication processes are uniquely different between these two categories resulting in clearly defined differences in the eddy current (bobbin) signals for the two categories and the criteria for determining the tubes that define high stress tubes. For short row tubes (Rows 1-9), the entire length of tubing is straightened and polished and thermally treated before forming the tube into U-bends. The thermal treatment of the entire straight length of tubing includes potentially more than one straightening/polishing/thermal treatment steps. After forming the U-bends, the U-bends are again thermally treated to relieve stresses in the U-bend region. Except for a short portion of tube below the tangent points, the straight legs of the tubes are not further subjected to any thermal or mechanical process. It is also noted that no distinction is made during the U-bend fabrication processes between hot leg and cold leg. Assignment of hot and cold legs is merely dependent on how the tubes are inserted into the tube bundle at SG assembly.

Tubes for Rows 10 and greater do not receive any further straightening/polishing/thermal treatment after forming the U-bends.

The relatively high strains the short row tubes are subjected to result in a significantly different material condition that results in a unique eddy current signal. The thermal treatment after forming restores the U-bend to the stress-free condition of the remainder of the tube. Consequently, if an abnormality in the final stress relief process occurs, the unique bobbin signals are relatively easy to identify. It is important to note that the eddy current probe does not measure the stress level in the tube; rather the probe identifies the changes in the material condition. The method for determining "signature" tubes is described in Reference 4.

The strains from forming the U-bends in tubes greater than Row 10 are not as large as those in the short row tubes. Though the strains in the U-bends of those tubes are greater than in the remainder (straight length) of the tubing. Because there is no clear-cut characteristic in the bobbin signal trace to identify potential high stress tubes among the high row tubes, an arbitrary criterion was selected that a tube with a U-bend signal offset greater than plus 2 standard deviations (+2-sigma) from the row-by-row mean offset would be considered a tube with potentially high stress. While the selection of the 2-sigma criterion is arbitrary it is considered to be a conservative threshold and was concluded to be a reasonable basis by which to define tubes that should be monitored by the Electric Power Research Institute (EPRI) per Reference 4. It is important to note that the criterion includes the requirement that both the hot leg and cold leg offset exceed the 2-sigma criterion. The reason for this is that, before U-bend forming, the entire tube was treated as a unit. That is, the last operation before forming the tube was a thermal stress relief of the entire tube and no further thermal or mechanical processes are applied after forming the U-bend.

Westinghouse is aware that, for different reasons, some utilities have identified additional tubes as "signature" tubes or "2-sigma" tubes beyond the initial population. Principally, these cases were related to the method for reporting the offset voltage. Westinghouse is also aware that in some cases, tubes may have been reported as 2-sigma tubes based on greater than 2-sigma offset on only one leg of the tube. Westinghouse maintains that this is not a proper interpretation of the condition of the tube based on the rationale above. The manufacturing process prohibits significant differences between the two legs of the tube, relative to the material condition. There may be other reasons for different U-bend offsets between the hot leg and cold leg, including the forming process itself, that may cause local material condition differences.

The high stress screening for Comanche Peak Unit 2 was performed consistent with the guideline published in Reference 4. Subsequently, the screening results were reviewed with respect to the known data acquisition errors that resulted in other plants adding to the original list of high-stress tubes. No similar errors were identified in the Comanche Peak data for high stress tubes. This confirmed that the original identification of high stress tubes was accurate and that no tubes that should have been classified as potentially containing higher residual stresses were missed.

If other plants altered the criteria for high stress tubes, inconsistent with the criteria originally established, it is possible that they may have identified other high stress tubes based on the revised criteria. These altered criteria are not known to Westinghouse and may not accurately reflect the manufacturing process of the SG tubes.

<u>Response 2.b.</u>

The normal tube population at Comanche Peak Unit 2 that is not identified as potentially containing higher residual stresses are inspected with bobbin probe. The applicable ETSS technique for detection of axial ODSCC at TSP locations is ETSS I28413. The performance-based 0.95 log-logistic POD from this ETSS is near 100% TW. A hybrid POD function can be created by merging a log-logistic and logistic fit based on the hit-miss data from the ETSS data set. By applying this method, a POD function is developed with a 0.95 detection capability of approximately 71% TW with the bobbin probe. When processing a uniform flaw distribution through this POD function, an undetected flaw distribution is developed with a 95th percentile maximum depth of approximately 60% TW. Using this flaw depth distribution for a single undetected flaw, a sensitivity case is performed using the fully probabilistic method to determine the maximum cycle length that could be achieved before the POB and/or POL leakage criteria are exceeded. For the purposes of this sensitivity study, all other inputs remain the same including length distribution, form factors and growth rates. Growth rates, which are the EPRI default growth rates from the SG Integrity Assessment Guidelines, have been demonstrated to be overly conservative based on a significant amount of re-analyzed thermally treated Alloy 600 (A600TT) stress corrosion cracking (SCC) flaw data. For a presumed flaw that escaped detection in a tube not identified as a “high-stress” tube, the maximum length OA for which the SG performance criteria for burst and leakage will be met is 4.45 effective full power years (EFPY) based on this sensitivity evaluation. When the OA interval is extended beyond 4.32 EFPY, the 5% POL criterion is exceeded. Translating this to Comanche Peak Unit 2 cycle lengths, 4.32 EFPY slightly exceeds the actual cycle lengths of Cycle 17 and 18 combined with the projected cycle length of 1.45 EFPY for Cycle 19. The cumulative duration for Cycles 17 through 19 at Comanche Peak 2 is 4.05 EFPY.

CPNPP-RAI-3:
Please describe the Weibull slope, characteristic life, and population size used in the analyses for the assumed potential cracking mechanisms.

Response:

Weibull cumulative failure projection models are applied to the fully probabilistic OA calculations for determining the number of undetected flaws to model. The Weibull calculations are based on the SCC flaws detected in A600TT tubing sorted by degradation mechanism, where similar mechanism totals are grouped together. The total tube population for the Weibull projections is the total number of tubes in the operating fleet A600TT steam generators in which SCC flaws have been detected. This is conservative, as it does not include the tubes in the several A600TT steam generators that have not experienced SCC degradation to date. The EFPY values of the failure data are normalized to a temperature of 618°F in order to be representative of the Comanche Peak Unit 2 hot leg temperature. The resultant Weibull curve provides a percentage of failures that are selected at 24.1 EFPY, which is the EFPY for the Comanche Peak Unit 2 SGs at RF18. The percentage of failures can be multiplied by 4,570 to determine the number of projected failures in a single SG at Comanche Peak Unit 2 for a given EFPY. With that preface, the slope, characteristic life and population size for each of the evaluated potential SCC mechanisms are included in the table below.

Potential Degradation Mechanism	Weibull Cumulative Failure Projection Input Parameters				Projected Failures in a Single SG of 4570 Tubes at 25.5 EFPY
	Slope	Characteristic Life	Failures	Total Population	
Circumferential ODSCC Tubesheet	3.2324	309.64	62	164907	1.2 (round up to 2.0)
Axial ODSCC Tubesheet	3.7761	405.25	12	164907	0.1 (round up to 2.0)
Axial PWSCC Tubesheet	3.7761	405.25	12	164907	0.1 (round up to 2.0)
Axial ODSCC Tube Support Plates	1.4846	6926.1	24	164907	1.0 (round up to 2.0)

References:

1. Comanche Peak Unit Nos 1 and 2, Request for Additional Information, License Amendment Request for One Time Change to Technical Specification 5.5.9 "UNIT 1 MODEL D76 AND UNIT 2 MODEL D5 STEAM GENERATOR (SG) PROGRAM," Docket Nos. 50-445 and 50-446, United States Nuclear Regulatory Commission, April 13, 2020.

2. SG-CDMP-20-13, Revision 0, "Comanche Peak Unit 2 Steam Generator Operational Assessment to Support Deferral of Planned Inspections from 2RF18 to 2RF19," Westinghouse Electric Company LLC, April 10, 2020.

3. TXX-20025 / CP-20200260, "EXIGENT LICENSE AMENDMENT REQUEST (LAR) 20-003 REVISION TO TECHNICAL SPECIFICATION (TS) 5.5.9, "UNIT 1 MODEL D76 AND UNIT 2 MODEL D5 STEAM GENERATOR (SG) PROGRAM," Vistra Energy, April 10, 2020 (ADAMS Accession No. ML20101M879).

4. EPRI SGMP Letter, "SGMP Information Letter on an Example Methodology for Screening of Alloy 600TT Tubing for the Seabrook Elevated Residual Stress Issue," Lawrence Womack, September 14,2004.

CPNPP-RAI-4:
The NRC staff found the proposed TS language unclear. For example, the proposed wording for Note B could be interpreted as applying to all future cycles. Would it be simpler to place footnotes referring to the appropriate TS section as below?

> Note A: For TS 5.5.9.d.2, "As a one-time change for Unit 2 Cycle 19 only, inspect each SG at least once every 54 effective full power months."
>
> Note B: For TS 5.5.9.d.2.c, "As a one-time change for Unit 2 Cycle 19 only, inspect 100% of the tubes every 90 effective full power months."

Response:

CPNPP will revise the proposed TS language as follows:

INSERT A – at the beginning of TS 5.5.9.d.2:

> "Implement a one-time change to TS 5.5.9.d.2, for Unit 2 Cycle 19 only, to inspect each SG at least every 54 effective full power months."

INSERT B – at the beginning of TS 5.5.9.d.2.c:

> "Implement a one-time change to TS 5.5.9.d.2.c, for Unit 2 Cycle 19 only, to inspect 100% of the tubes every 90 effective full power months."

The marked-up copy of TS 5.5.9 is included as an attachment to this letter (TXX-20032).

CPNPP-RAI-5:
Page 9/18 in the Enclosure discusses the evaluation of existing mechanisms, in particular tube wear at anti-vibration bars (AVBs). Please confirm that the maximum projected depths for the largest existing indication and undetected indication were inadvertently switched (i.e., 55.3% through wall (TW) for existing maximum depth indication and 38.4% for an undetected indication).

Response:

The values were inadvertently switched. Page 9/18 of the Enclosure should read as follows:

1. List mechanisms considered and reason for consideration
   Existing Degradation Mechanisms
   a. Projected Tube Wear at AVBs
      Existing 55.3% TW with burst pressure of 5075 psi. Criterion is less than 69.4% TW with burst pressure greater than or equal to 3909 psi.

      Undetected 38.4% TW with burst pressure of 6438 psi. Criterion is less than 69.4% TW with burst pressure greater than or equal to 3909 psi.

Prediction of existing AVB Wear at 2RF19 starts with 39% TW is projected to be no worse than 55.3% TW with a burst pressure of 5075 psi. The bounding load limit is 69.4% TW with a burst pressure greater than or equal to 3909 psi.

Prediction of undetected AVB Wear at 2RF19 starts with 17% TW is projected to be no worse than 38.4% TW with a burst pressure of 6438 psi. The bounding load limit is 69.4% TW with a burst pressure greater than or equal to 3909 psi.

CPNPP-RAI-6:
Clarify whether the applicable TS limiting conditions for operation (LCOs) and surveillance requirements for the SG tube integrity, tube plugging criteria and reactor coolant system (RCS) operational leakage requirements are affected by the proposed changes.

Response:

The applicable TS limiting conditions for operation (LCOs) and surveillance requirements for the SG tube integrity, tube plugging criteria and reactor coolant system (RCS) operational leakage requirements are not affected by the proposed changes.

Review of the associated technical specifications:

1. TS 3.4.13 RCS Operational LEAKAGE

   TS 3.4.13 is applicable in MODES 1, 2, 3, and 4.

   RCS operational leakage for primary to secondary leakage through any one SG remains at 150 gallons per day (gpd). Surveillance Requirement (SR) 3.4.13.2 will, "Verify primary to secondary LEAKAGE is ≤150 gallons per day through any one SG," every 72 hours per the Surveillance Frequency Control Program (SFCP). Administratively leakage is verified every 24 hours.

   TS Bases 3.4.13:
   SR 3.4.13 "verifies that primary to secondary LEAKAGE is less than or equal to 150 gallons per day through any one SG. Satisfying the primary to secondary LEAKAGE limit ensures that the operational LEAKAGE performance criterion in the Steam Generator Program is met. If this SR is not met, the performance criterion is not met and LCO 3.4.17, "Steam Generator Tube Integrity," should be entered."

   The proposed changes to TS 5.5.9, do not require a change to TS 3.4.13 or TSB 3.4.13. The 150 gpd limit is maintained.

2. TS 3.4.17 Steam Generator (SG) Tube Integrity

   TS 3.4.17 is applicable in MODES 1, 2, 3, and 4 with a separate entry allowed each SG tube.

   If SG tube integrity is not maintained until the next refueling outage or tube inspection, then the affected tube(s) must be plugged in accordance with the SG Program (TS 5.5.9). Any tube plugging must be completed prior to MODE 4 entry.

The proposed change along with the Operational Assessment provide the basis for SG tube integrity assurance through an additional operating cycle.

TS Bases 3.4.17:
"Specification 5.5.9, "Steam Generator (SG) Program," requires that a program be established and implemented to ensure that SG tube integrity is maintained. Pursuant to Specification 5.5.9, tube integrity is maintained when the SG performance criteria are met. There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. The SG performance criteria are described in Specification 5.5.9. Meeting the SG performance criteria provides reasonable assurance of maintaining tube integrity at normal and accident conditions."

The proposed changes to TS 5.5.9, do not require a change to TS 3.4.17 or TSB 3.4.17. The 150 gpd limit and criteria for integrity and tube plugging are maintained.

Attachment 2 to TXX-20032

Marked-up Copy of CPNPP TS 5.5.9

5.5 Programs and Manuals (continued)

5.5.7 Reactor Coolant Pump Flywheel Inspection Program

This program shall provide for the inspection of each reactor coolant pump flywheel per the recommendations of Regulatory Position C.4.b of Regulatory Guide 1.14, Revision 1, August 1975. In lieu of Position C.4.b(1) and C.4.b(2), a qualified in-place UT examination over the volume from the inner bore of the flywheel to the circle one-half of the outer radius or a surface examination (MT and/or PT) of exposed surfaces of the removed flywheels may be conducted at 20 year intervals.

5.5.8 Deleted

5.5.9 Unit 1 Model D76 and Unit 2 Model D5 Steam Generator (SG) Program

A Steam Generator Program shall be established and implemented to ensure that SG tube integrity is maintained. In addition, the Steam Generator Program shall include the following:

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the “as found” condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The “as-found” condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected or plugged to confirm that the performance criteria are being met.

b. Performance criteria for SG tube integrity. SG tube integrity shall be maintained by meeting the performance criteria for tube structural integrity, accident induced leakage, and operational LEAKAGE.

   1. Structural integrity performance criterion: All in-service steam generator tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cool down), all anticipated transients included in the design specification, and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination

5.5 Programs and Manuals (continued)

5.5.9 Unit 1 Model D76 and Unit 2 Model D5 Steam Generator (SG) Program (continued)

with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.

2. Accident induced leakage performance criterion: The primary to secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 1 gpm per SG.

3. The operational LEAKAGE performance criterion is specified in LCO 3.4.13, “RCS Operational LEAKAGE.”

c. Provisions for SG tube plugging criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

1. The following alternate tube plugging criteria shall be applied as an alternative to the 40% depth based criteria:

a. For Unit 2 only, tubes with service-induced flaws located greater than 14.01 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 14.01 inches below the top of the tubesheet shall be plugged upon detection.

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. For Unit 1, the number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube plugging criteria. For Unit 2, the number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube from 14.01 inches below the top of the tubesheet on the hot leg side to 14.01 inches below the top of the tubesheet on the cold leg side and that may satisfy the applicable tube plugging criteria. The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements below, the inspection scope, inspection methods and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. A degradation assessment shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this

5.5.9 Unit 1 Model D76 and Unit 2 Model D5 Steam Generator (SG) Program (continued)

assessment, to determine which inspection methods need to be employed and at what locations.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG installation.

INSERT A

2. For the Unit 2 model D5 steam generators (Alloy 600 thermally treated) 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 a, b, and c 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.

   a. 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;

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

INSERT B

   c. 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.

3. For the Unit 1 model Delta-76 steam generators (Alloy 690 thermally treated) after the first refueling outage following SG installation, inspect each SG at least every 72 effective full power months or at least every

5.5 Programs and Manuals

5.5.9 Unit 1 Model D76 and Unit 2 Model D5 Steam Generator (SG) Program (continued)

third 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 a, b, c and d 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.

a. After the first refueling outage following SG installation, inspect 100% of the tubes during the next 144 effective full power months. This constitutes the first inspection period;

b. During the next 120 effective full power months, inspect 100% of the tubes. This constitutes the second inspection period;

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

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

4. For Unit 1, if crack indications are found in any SG tube, then the next inspection for each affected and potentially affected SG for the degradation mechanism that caused the crack indications shall not exceed 24 effective full power months or one refueling outage (whichever results in more frequent inspections). For Unit 2, if crack indications are found in any SG tube from 14.01 inches below the top of the tubesheet on the hot leg side to 14.01 inches below the top of the tubesheet on the cold leg side, then the next inspection for each affected and potentially affected SG for the degradation mechanism

5.5.9 Unit 1 Model D76 and Unit 2 Model D5 Steam Generator (SG) Program (continued)

that caused the crack indications shall not exceed 24 effective full power months or one refueling outage (whichever results in more frequent inspections). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

e. Provisions for monitoring operational primary to secondary LEAKAGE.

5.5.10 Secondary Water Chemistry Program

This program provides controls for monitoring secondary water chemistry to inhibit SG tube degradation and low pressure turbine disc stress corrosion cracking. The program shall include:

a. Identification of a sampling schedule for the critical variables and control points for these variables;

b. Identification of the procedures used to measure the values of the critical variables;

c. Identification of process sampling points, which shall include monitoring the discharge of the condensate pumps for evidence of condenser in leakage;

d. Procedures for the recording and management of data;

e. Procedures defining corrective actions for all off control point chemistry conditions; and

f. A procedure identifying the authority responsible for the interpretation of the data and the sequence and timing of administrative events, which is required to initiate corrective action.

5.5.11 Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in Regulatory Guide 1.52, Revision 2 and in accordance with Regulatory Guide 1.52, Revision 2, ANSI/ASME N509-1980, ANSI/ASME N510-1980, and ASTM D3803-1989.

INSERT A

“Implement a one-time change to TS 5.5.9.d.2, for Unit 2 Cycle 19 only, to inspect each SG at least every 54 effective full power months.”

INSERT B

"Implement a one-time change to TS 5.5.9.d.2.c, for Unit 2 Cycle 19 only, to inspect 100% of the tubes every 90 effective full power months.”