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Attention: Document Control Desk
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VIRGINIA ELECTRIC AND POWER COMPANY (DOMINION)
NORTH ANNA POWER STATION UNITS 1 AND 2
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION
STEAM GENERATOR TUBE INSPECTION REPORT

In October 9, 2007 and November 15, 2007 letters (Serial Nos. 07-0583 and 07-0704), Dominion submitted 180-day steam generator tube inspection reports for North Anna Power Station Units 2 and 1, respectively. In a February 19, 2008 letter, the NRC requested information to complete their evaluation of the steam generator inspection results. The attachment to this letter provides the requested information.

This letter does not establish any new commitments. Should you have any questions or require additional information, please contact Mr. Thomas Shaub at (804) 273-2763.

Very truly yours,

C. L. Funderburk, Director
Nuclear Licensing and Operations Support
Dominion Resources Services, Inc.
for Virginia Electric and Power Company

Attachment

cc: U.S. Nuclear Regulatory Commission
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ATTACHMENT

NORTH ANNA UNITS 1 AND 2
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION
REGARDING STEAM GENERATOR TUBE INSPECTION REPORTS

NORTH ANNA UNITS 1 AND 2
REQUEST FOR ADDITIONAL INFORMATION REGARDING STEAM GENERATOR TUBE INSPECTION REPORTS

In October 9, 2007 and November 15, 2007 letters (Serial Nos. 07-0583 and 07-0704), Dominion submitted 180-day steam generator tube inspection reports for North Anna Power Station Units 2 and 1, respectively. In a February 19, 2008 letter, the NRC requested information to complete their evaluation of the steam generator inspection results.

Question pertaining to North Anna Unit 1:

NRC Question 1

One tube was plugged in Unit 1 since a permeability indication rendered a significant portion of the tube un-inspectable. Please discuss how the integrity of this tube was assessed (i.e., did the tube satisfy the performance criteria) if it could not be fully inspected. For example, was an insitu pressure test performed?

Dominion Response

In 2007, one North Anna Unit 2 (not Unit 1) tube was removed from service due to interfering permeability indications. Detection of corrosion in the presence of such signal interference can be especially challenging. Therefore, the tube in question was conservatively and preventatively removed from service to eliminate any future concern about a potential reduction of probability of detection should corrosion eventually develop in the North Anna Unit 2 SGs. There has been no evidence during any of the North Anna SG tube inspections performed to date, including the extensive rotating probe examinations performed in the tube that was preventively plugged, which would suggest that such degradation existed in this tube. In-situ pressure testing was not performed.

Questions pertaining to North Anna Unit 1 and 2:

NRC Question 2

For each RFO and steam generator (SG) tube inspection since installation of the SGs, please provide the cumulative effective full power months that the SGs have operated.

Dominion Response

The table below provides the cumulative effective full power operating months (EFPM) for both units since SG replacement.

Unit #1	Unit #2
Fall 1994 (1st ISI=16.2 EFPM)	Fall 1996 (1st ISI=15.0 EFPM)
Winter 1996 (31.8 EFPM)	Spring 1998 (31.0 EFPM)
Spring 1997 (45.6 EFPM)	Fall 1999 (47.2 EFPM)
Fall 1998 (60.4 EFPM)	Spring 2001 (63.6 EFPM)
Spring 2000 (77.1 EFPM)	Fall 2002 (78.8 EFPM)
Fall 2001 (93.5 EFPM)	Spring 2004 (93.6 EFPM)
Spring 2003 (109.7 EFPM)	Fall 2005 (109.5 EFPM)
Fall 2004 (125.9 EFPM)	Spring 2007 (125.9 EFPM)
Spring 2006 (142.6 EFPM)	
Fall 2007 (159.3 EFPM)	

NRC Question 3

It was indicated that the secondary-side inspections did not reveal any component degradation that would compromise tube integrity. Please discuss the results of the inspections of the secondary-side internals (e.g., any degradation/deterioration observed, any extensive deposits observed at the tube support plate openings).

Dominion Response

The following describes secondary side examinations and results for the inspections performed in the Unit 1 and Unit 2 SGs during 2007 outages, and are typical of those routinely performed during SG inspection outages.

Unit 1 and Unit 2:

Components in the upper two decks, primary and secondary separators, swirl vanes, drain pipes, deck attachment welds, ladders etc., were inspected and found to be acceptable from an operational and structural standpoint. Minimal deposition was observed in the primary and secondary separators and other steam drum components. However, the tangential outlet nozzles of the primary separators contained a somewhat heavier crystalline deposit.

Secondary separator drain pipes [approximately 2 inches outside diameter (OD)] transport liquid water from the secondary moisture separator drain pans to the lower deck area. Each pipe is held in place at its lower end with a bracket that is welded to its adjacent primary moisture separator downcomer. The drain pipe goes through a hole in the bracket. A cup approximately twice the diameter of the pipe is welded to the end of each pipe. During the examination of the SG "A" in Unit 1, and SGs "A" and "C" in Unit 2 steam drums, a small clearance was noted between the drain pipe and the bracket which allowed slight movement of the pipe within the bracket. This condition was noted on two of the three drain pipes in Unit 1 SG "A," two of the three drain pipes in Unit 2 SG "A," and one of the three drain pipes in Unit 2 SG "C." There was no appreciable wear at the interface between the pipes and the brackets. The pipes are original equipment, hence this condition developed over an operating period of several decades. This condition has been evaluated and it has been determined that there is reasonable assurance that this condition will not impact tube integrity prior to the next inspection after another three fuel cycles of operation.

<u>Unit 1:</u>

The internal feedring/J-nozzle interfaces of all J-nozzles in SG "A" were visually examined. The videos from SG "A" were reviewed side by side with videos from the previous inspection in 2001 in order to identify any locations where flow assisted corrosion (FAC) may have continued to advance. This review revealed evidence of only minor change since the 2001 inspection. Although substantial change was not identified in any case, one interface was scheduled for follow up testing with ultrasonic (UT) techniques. The UT examination revealed minimal change since the previous UT examination of this J-nozzle (performed in 1996).

The plugged bottom nozzles in the "A" SG feedring were examined from the exterior. No signs of leaking plugs or erosion sites were noted. External examination of the feedring revealed some discoloration of moisture separator riser barrel and feedring OD surfaces adjacent to several J-nozzles due to overspray. No significant material loss was noted at any of these overspray sites.

UT thickness measurements were taken in selected regions of the SG "A" feedring during this outage for the purpose of monitoring for FAC related degradation. All measurements confirmed that the wall thickness exceeds the minimum design requirement by a significant margin. Based on indicated growth since the last examination, it would take an additional 5 operating cycles to reach the currently evaluated minimum acceptable wall thickness at the most limiting location.

Portions of the upper tube bundle and anti-vibration bars (AVBs) were examined from the steam drum through the primary separator swirl vanes. These examinations included the tube bundle along the lowest (#6) and mid elevation (#5) AVB sets on the cold leg side of the tube bundle. Light to moderate deposits were noted on the tube surfaces and the AVB surfaces. Deposit material bridged between the tube wall and the AVB in most locations. The mid level (#5) AVB contained heavier deposits overall than the lower level (#6) AVB. Structurally, all components viewed in this area were sound with no evidence of erosion or corrosion. The quantity and appearance of the deposits in the Unit 1 "A" steam generator are comparable to that seen in the other steam generators in Unit 1 and are similar to the deposits observed in Unit 2 during previous outages.

In-bundle visual examinations were performed from the 7th tube support plate (TSP) inspection port in the hot and cold legs. The row 1 u-bend region at the TSP (i.e., divider lane) was examined over its full length. No material abnormalities were observed. All welds and structural components viewed were sound and intact. Moderate levels of tube and TSP deposition had a crystalline appearance and were somewhat adherent. The periphery of the cold leg showed the heaviest accumulation of deposition (1/16" to 1/8" thick). In general, the inner bundle region of the cold leg contained slightly more deposition than the hot leg. The tube deposits were slightly heavier near the periphery and divider lane. All broached flow holes viewed were open, with some evidence of light deposit coating on broach hole walls. Drop down examinations from 7th TSP revealed 6th TSP deposits which were slightly heavier than those at the 7th TSP. Below this elevation increasing cleanliness was observed with decreasing elevation: the 5th TSP was slightly cleaner than the 6th TSP and views of the 4th TSP showed light to moderate deposits on the underside with the cold leg deposits being lighter than the hot leg.

<u>Unit 2:</u>

The internal feedring/j-nozzle interfaces of all j-nozzles in SGs "A" and "C" were visually examined. The videos from SG "A" were reviewed side by side with videos from the previous inspection in 2002 in order to identify any locations where FAC may have continued to advance. This review revealed no instances of change since the 2002 inspection and none were judged to require follow up testing with UT techniques. The plugged bottom nozzles in the "A" SG feedring were examined from the exterior. No signs of leaking plugs or erosion sites were noted. No evidence of FAC was identified during the SG "C" video review, as expected, since this feedring had been replaced with upgraded materials during the 1995 SG replacement outage. External examination of the feedrings revealed some discoloration of moisture separator riser barrel and feedring OD surfaces adjacent to several j-nozzles due to overspray. No significant material loss was noted at any of these overspray sites.

Portions of the upper tube bundle and AVBs were examined from the steam drum through the primary separator swirl vanes. Light to moderate deposits were noted on the tube surfaces and the AVB surfaces. The "A" SG contained slightly heavier deposits than the "C" SG in this region, with some of the deposit material noted as being disturbed by the passage of the video probe along the AVBs. The "C" SG deposits were tightly adherent and not disturbed by the probe in the areas viewed. Structurally, all components viewed in this area were sound with no evidence of erosion or corrosion. The quantity and appearance of the deposits in these two steam generators are comparable to that seen in the other steam generator in Unit 2 and are similar to the deposits observed in Unit 1 as well.

In-bundle visual examinations were performed from the 7th TSP inspection port in the hot and cold legs in each SG. Each divider lane was examined over its full length. No material abnormalities were observed. All welds and structural components viewed were sound and intact. Somewhat adherent, light to moderate tube and TSP deposition was observed, with the heaviest accumulation being in the cold leg (1/16" to 1/8" thick). In general, the inner bundle region of the cold leg was slightly cleaner than the hot leg. The tube deposits were slightly heavier near the periphery and divider lane. All broached flow holes viewed were open, with some evidence of light deposit coating on broach hole walls. Drop down examinations from the 7th TSP revealed 6th TSP deposits which were similar to those at the 7th TSP. Below this elevation increasing cleanliness was observed with decreasing elevation: the 5th TSP was cleaner than the 6th TSP and views of the 4th TSP showed very light deposits on the underside with the cold leg deposits being lighter than the hot leg. Compared to the most recent visual examination of SG "B" during 2R17 (2005), SG "A" and SG "C" show very similar deposit conditions.

NRC Question 4

Tube wear was listed as a potential degradation mechanism for the straight-leg and antivibration bar tangent points for Rows 8, 14, and 26. Please clarify why the only rows considered susceptible to this degradation mechanism are Rows 8, 14, and 26.

Dominion Response

Only rows 8, 14, and 26 intersect with the "V" portion of the AVBs, forming the "tangent" points referred to in the description. The straight portions of an AVB intersect all tubes in rows greater than its tangent point. For example, the tangent point of the largest AVB intersects row 8; and the two legs of that AVB intersect all rows greater than row 8. All AVB intersections are considered to be potentially susceptible to tube wear. No AVB wear has yet to be identified in the North Anna SGs.

NRC Question 5

With respect to the design of your SGs, please confirm that the tubes are arranged in a square pitch/pattern and they were manufactured by Sandvik. In addition, please provide the radius of the Row 1 tubes and the tubesheet thickness (with and without clad).

Dominion Response

The North Anna SG design is provided as follows:

Tube arrangement:	Square pitch
Tube manufacturer:	Sandvik
Row 1 bend radius:	2.187 inches
Tubesheet thickness with clad:	21.42 inches
Tubesheet thickness without clad:	21.17 inch

NRC Question 6

It was indicated that the rotating coil probe was used to inspect freespan dents/bulges in Unit 1 and dents/dings/bulges in Unit 2 that measured greater than 2-volts (as determined by the bobbin coil). Please provide the information in Table 1 of the reports for these locations (e.g., these locations are potentially susceptible to primary water stress corrosion cracking and outside diameter stress corrosion cracking). Please discuss why freespan dings were not inspected in Unit 1. In addition, please discuss whether there are any dents/dings/bulges at non-freespan locations and whether these locations are susceptible to degradation (potential, relevant, existing). If so, discuss what examinations, if any, were performed at these locations.

Dominion Response

In this context, the terms ding and dent are used interchangeably and refer to the same physical condition; hence, "dings" were not excluded from the Unit 1 rotating coil inspection sample as is assumed in the question. Although a majority (approximately 75%) of North Anna dent/ding/bulge indications is located in the freespan, the subject inspections were not limited to those in the freespan. Instead, the sampling was prioritized on the basis of indication voltage and SG leg. In both Unit 1 and Unit 2, all dent/ding locations whose amplitude exceeded 5 volts were examined with the rotating probe regardless of leg (12 tests in Unit 1 and 2 tests in Unit 2). In addition, a sample of hot leg dents/dings with amplitude between 2 and 5 volts were also examined. Overall during each inspection, more than 20% of the total number of reported dents/dings was examined with the rotating probe (48 tests total in Unit 1, 24 tests total in Unit 2). All reported bulge indications were examined with the rotating probe (3 tests in Unit 1, no tests in Unit 2). No degradation was identified.

Because none of these locations are considered to be susceptible to corrosion at this time, the inspections were performed for informational purposes. The Table 1 entry applicable to both Unit 1 and Unit 2 is provided below:

Classification	Degradation Mechanism	Location	Probe Type
Relevant/Informational Inspection	ODSCC PWSCC	Dents/Dings/Bulges	+Point™ – Detection and Sizing