VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

October 9, 2008

United States Nuclear Regulatory Commission		Serial No.	08-0272A
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VIRGINIA ELECTRIC AND POWER COMPANY
SURRY POWER STATION UNIT 1
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION
2007 STEAM GENERATOR INSERVICE INSPECTION REPORT

By letter dated May 21, 2008 (ML081560216), Virginia Electric and Power Company (Dominion) submitted information summarizing the results of steam generator (SG) tube inspections performed at Surry Power Station Unit 1 during the fall 2007 refueling outage. After review of the provided information, the NRC staff determined that additional information is required to complete their review. The NRC's questions and Dominion's responses are provided in the attachment.

If you have any questions or require additional information, please contact Mr. Trace J. Niemi at (757) 365-2848.

Very truly yours,

G. T. Bischof
Site Vice President

Commitments made in this letter: None

Attachment
Response to NRC Request for Additional Information Regarding 2007 Steam Generator Inservice Inspection Report, Surry Power Station Unit 1

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NRR

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ATTACHMENT

Response to NRC Request for Additional Information Regarding 2007 Steam Generator Inservice Inspection Report

Surry Power Station Unit 1

Virginia Electric and Power Company
(Dominion)

By letter dated May 21, 2008 (Serial No. 08-0272), Virginia Electric and Power Company (Dominion) submitted information summarizing the results of the fall 2007 steam generator (SG) tube inspections performed at Surry Power Station Unit 1. On September 10, 2008, the NRC requested additional information related to the SG inspections. The NRC questions and Dominion's response are provided below.

NRC Question 1

In Table 6 of your May 21, 2008 letter, you provided the effective full power years for each of your refueling outages except for the October 2007 outage. Please provide the effective full power years for your October 2007 inspection. In addition, on page 1 of the report, you indicated that there were 234.4 effective full power months of operation. Please clarify which refueling outage this corresponds to or whether it represents some other period of time (e.g., time between the first refueling outage and the 2007 outage).

Dominion Response

Surry Unit 1 operated for 20.9 EFPY (250.4 EFPM) from initial startup with the replacement SGs (July 1981) through the October 2007 refueling outage. The value 234.4 EFPM corresponds with the operating period from the first refueling outage following SG replacement (February 1983), through the October 2007 refueling outage.

NRC Question 2

Regarding your inspection of the plugs, please discuss whether these inspections also included verification that all previously installed plugs are still present (i.e., If 21 tubes were plugged, do you verify that there are 21 plugs in each leg of the steam generator?)

Dominion Response

The October 2007 inspection verified that all plugs previously installed (21 tubes) were still properly in-place in the hot leg and cold leg of SG B.

NRC Question 3

Please discuss the results of the upper bundle flush in the three steam generators. For example, discuss the extent to which the quatrefoil-shaped holes in the tube support plates are blocked.

Dominion Response

Table 1 in our letter of May 21, 2008 identifies the mass of deposit material removed from each SG during the October 2007 refueling outage. This is the total amount of material removed by the combined effort of upper bundle flushing, lancing of the flow distribution baffle, and lancing of the top of tubesheet.

Visual examinations of the Unit 1 upper tube support plates (TSPs) have been periodically performed since the mid-1990s. Although minor deposition within the broach holes has been noted, to date, the extent of deposition is judged to have a negligible effect on local flow behavior and pressure drop within the SGs.

During the October 2007 refueling outage, portions of the upper tube bundle and 7th TSP were examined from the steam drum through two primary separator swirl vanes in SG B. This inspection documented the Unit 1 upper bundle conditions prior to the performance of the upper bundle flush (UBF). This pre-UBF examination indicated that deposit accumulation and bridging at anti-vibration bar (AVB)/tube intersections has continued to increase, as has tube deposition in the AVB region and at the 7th TSP. Some deposition within the broached openings of the 7th TSP was also noted, as was light to moderate deposition on the surface of the 7th TSP in the inner bundle regions.

A post-UBF visual examination was performed in SG A. The examination revealed that post-UBF deposit quantity was somewhat reduced when compared with the results from the SG B examination. Loose deposit material on the AVB and tube surfaces in-bundle had been reduced. Accumulation and bridging at AVB/tube intersections was still present, but was also reduced. The periphery tube surface deposits just above the 7th TSP, which were observed during the SG B pre-UBF inspection, were not present on the periphery tubes in SG A post-UBF. In-bundle top of 7th TSP observations also revealed a slight decrease in the amount of surface deposition. No deposit build up was noted on the lower edge of the periphery broached openings as was observed in SG B during the pre-UBF inspection.

NRC Question 4

It was indicated that ultrasonic examination of the feedrings were performed. Please discuss the extent and nature of the degradation observed at this location (e.g., flow accelerated corrosion affecting the header and "x" nozzles).

Dominion Response

During the October 2007 refueling outage, a visual inspection was performed on the internal J-nozzle feedring weld interfaces in SG B consistent with Surry's monitoring program for flow assisted corrosion (FAC) in this region. Evidence of minor FAC was observed, with minimal evidence of change from the previous visual examination performed in this SG (April 2003). None were identified for follow-up UT examination.

To monitor the progression of FAC in the feedrings, UT thickness measurements were taken in all three SGs during the October 2007 outage. All measurements confirmed that the wall thickness exceeded the minimum design requirements.

The largest rate of thickness reduction observed since the last inspection in any SG was in the SG A inlet reducer (144 mils/cycle). This value is based on average thickness measurements taken during end-of-cycle (EOC) 20 and EOC21. Due to the difficulty associated with inspecting this particular component, and uncertainty as to whether the identical locations were examined during each outage, this result is suspect.

The next largest rate of thickness reduction was observed in the right side elbow of SG A (39 mils/cycle). This rate is based on minimum measured thickness values and is generally considered to be less reliable than rates based on consecutive average thickness values. The rate for this component as indicated by average thickness measurements is only 2 mils/cycle.

The most limiting component based on current thickness, rate of progression, and allowable minimum thickness is the downstream portion of the inlet reducer in SG A which will require remediation or re-inspection by EOC22. The next most limiting projection is for the crossover pipe in SG B which will require remediation or re-inspection by EOC25 based on minimum measured thickness values.

NRC Question 5

It was indicated that secondary side inspections indicated no component degradation that would compromise tube integrity. Please discuss whether any degradation was observed and discuss the source/nature of the degradation (e.g., erosion of swirl vanes).

Dominion Response

The only degradation of secondary side SG components observed was FAC of the feedring and J-nozzle / feedring weld interfaces (discussed above). No degradation of any other secondary side components was identified.

NRC Question 6

Please discuss whether there are any tubes that are not fully expanded into the tubesheet. If so, discuss whether a rotating probe inspection was performed in the tubesheet region of these tubes.

Dominion Response

There are no tubes in SG B that are not fully expanded into the tubesheet.

NRC Question 7

Please discuss whether any new dents were observed during the inspection (in particular at the 6th and 7th tube support plates where denting has been observed near the wedges). If there are any new dents or the size of the existing dents is increasing in magnitude, please discuss any corrective actions that were taken.

Dominion Response

During the October 2007 SG B bobbin probe examination, 501 dents measuring $\geq$ 2 volts were reported in 389 tubes. In addition to the bobbin probe examination, more than 20% of dent indications $\geq$ 2 volts were also tested with +Point probes (88 tubes / 104 tests), including all dents $\geq$5 volts. No degradation was identified.

The dents reported in SG B appear to be randomly distributed throughout the tube bundle and have no strong bias towards tube supports 6 and 7 or the wedge regions. Historical data reviews of dents reported during 2007 confirmed that none of the reported indications were new (i.e., all were present previously), and none revealed evidence of increasing magnitude.

NRC Question 8

Please discuss whether any tubes exhibit the eddy current offset that is representative of potentially higher residual stress (such as observed at Seabrook). If there are tubes that have this offset, discuss the number of tubes with the offset including the number in the "high rows" (non-stress relieved in the U-bend) and the "low rows." Please discuss the extent to which rotating probe inspections were performed on these tubes (e.g., at dents, at expansion transitions).

Dominion Response

In SG B, a total of 22 tubes exhibit eddy current offset signals representative of potentially higher residual stress; all 22 are in "high rows." No SG B tubes exhibit the "low row" eddy current signature identified at Seabrook.

The table below identifies the dent signals reported in the 22 tubes and confirms that they were examined with +Point probes. In addition, the 22 hot leg expansion transitions and three of the 22 cold leg expansion transitions were also examined with +Point probes. The table below represents the number of indications in the 22 tube subset that were tested with eddy current. No degradation was identified as a result of these examinations.

Indications in Tubes with Potentially Higher Residual Stress (SG B)
(number tubes / number indications)

Indication Type	Reported w/Bobbin Probe	Examined w/+Point Probe
Historical Distorted Dent (DDH)	1 / 1	1 / 1
Dent (DNT)	2 / 3	2 / 3
Historical Non-Quantifiable Bobbin Indication (NQH)	3 / 4	3 / 4
Bulge Within Tubesheet (OXP) – Cold Leg	3 / 5	3 / 5
OXP – Hot Leg	2 / 2	2 / 2

NRC Question 9

During a conference call during your 2007 outage, the NRC staff was under the impression that three loose parts were removed from a location where two pit-like indications were detected. As a result, these "pit-like" indications were attributed to wear from a loose part rather than to pitting. However, in your letter dated May 21, 2008, you indicate that no loose parts were near the four tubes with volumetric indications. Please clarify.

Dominion Response

Our May 21, 2008 letter stated that no objects were found immediately adjacent to the three damaged tubes clustered adjacent to each other at Row 40 Col 50, Row 40 Col 51, and Row 41 Col 51. However, one foreign object was found approximately one tube away from the cluster, and two other foreign objects were found approximately 3 and 6 tubes away from the cluster. Due to the clustered relationship of the affected tubes, their location near the bundle periphery – a region typically affected by foreign object wear and not subject to sludge pile formation, and the identification of foreign objects in the vicinity of the degradation, this degradation is believed to have been caused by a foreign object. As discussed in our letter, the remaining indication identified in Row 1 Col 7 is mechanical damage attributed to a previous maintenance process.

NRC Question 10

For the permeability variation that did not permit a high quality inspection, please discuss how it was confirmed that this tube had adequate integrity.

Dominion Response

A total of 12 permeability variation indications (PVN) were reported during the bobbin probe examination of SG B. One of the 12 indications, located in cold leg freespan between the second and third TSP, could not be fully suppressed with a magnetically biased +Point probe. Therefore, the tube in question was conservatively and preventively removed from service to eliminate any future concern about a potential reduction of probability of detection (POD) should corrosion eventually develop in the affected region of the Surry Unit 1 SG tubes.

There has been no evidence during any of the Surry SG tube inspections performed to date (either unit), including the 11 other PVN locations which were successfully examined with +Point probes during the October 2007 outage, that would suggest that degradation existed in this tube. Absent evidence of degradation, there is reasonable assurance that the tube removed from service had adequate integrity.