VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

January 25, 2012

U.S. Nuclear Regulatory Commission
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Washington, D.C. 20555

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VIRGINIA ELECTRIC AND POWER COMPANY (DOMINION)
NORTH ANNA POWER STATION UNIT 1
STEAM GENERATOR TUBE INSPECTION REPORT

Pursuant to Technical Specification 5.6.7 for North Anna Power Station Unit 1, Dominion is required to submit a 180-day steam generator tube inspection report. The attachment to this letter provides the steam generator tube inspection report for the North Anna Unit 1 fall 2011 outage.

Should you have any questions or require additional information, please contact Mr. Jay Leberstien at (540) 894-2574.

Very truly yours,

Gerald T. Bischof
Site Vice President

Attachment

Commitments made in this letter: None

A001
NRR

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ATTACHMENT

NORTH ANNA UNIT 1
180-DAY NRC REPORT REGARDING STEAM GENERATOR TUBE INSPECTION PER TECHNICAL SPECIFICATION 5.6.7

VIRGINIA ELECTRIC AND POWER COMPANY
(DOMINION)

FALL 2011 - NORTH ANNA UNIT 1 STEAM GENERATOR INSPECTIONS

During the North Anna Unit 1 fall 2011 outage, steam generator (SG) inspections were completed in accordance with TS 5.5.8.d for steam generator "A". Transmittal of this report satisfies the North Anna Power Station Technical Specification (TS) reporting requirement specified in Section 5.6.7.

The Unit 1 steam generators have accrued 16.9 Effective Full Power Years (EFPY) of operation as of September 2011.

Initial entry into Mode 4 occurred on November 11, 2011 (1420 hours); therefore, this report is required to be submitted by May 9, 2012.

Italicized wording represents TS verbiage. The required information is provided under each reporting requirement as follows:

A report shall be submitted within 180 days after the initial entry into Mode 4 following completion of an inspection performed in accordance with the Specification 5.5.8, "Steam Generator (SG) Program." The report shall include:

a. *The scope of inspections performed on each SG*

The following primary side inspections were performed in steam generator "A":

- Video examination of both channel heads (as-found / as-left) (there were no previously installed tube plugs in SG "A" and none were installed during the fall 2011 outage)
- 100% full-length inspection utilizing bobbin coil probe for all tubes except for Row 1 U-bends
- 28% hot leg top of tubesheet (+/- 3") utilizing rotating coil probe with tube selection including 50% of the secondary side critical area in the sludge zone, 50% of all tubes within five tubes of the bundle periphery, and other randomly sampled locations
- 16% cold leg top of tubesheet (+/- 3") utilizing rotating coil probe with tube sample constituting 50% of all tubes within five tubes of the bundle periphery
- 100% Row 1 U-bend region utilizing rotating coil probe
- Special interest inspections of dents/dings with rotating coil probe (Sample: 100% of dents/ding $\geq$ 5 Volts; 3% of dents/ding $\geq$ 2 Volts and < 5 Volts)
- Inspection of all bobbin identified I-codes (i.e. possible damage indications) with rotating coil probe (Sample: 7 tests)
- Special interest rotating coil probe exams of largest voltage tubesheet overexpansions (OXP) (Sample: 31 hot leg tests and 14 cold leg tests)
- Rotating coil probe examinations of hot leg historical manufacturing brandish mark (MBH) indications (Sample: 35%)

The following secondary side inspections were performed in steam generator "A":

- Steam drum visual inspections to evaluate the cleanliness and structural condition of all accessible subcomponents including moisture separators, drain systems, and interior surfaces.
- Drop down examinations through the primary separators to assess the cleanliness and structural condition of the upper tube bundle and anti-vibration bars (AVB) supports.
- Visual inspections of J-nozzle to feedring internal interface for flow assisted corrosion.
- Visual inspections of upper tube support plates via 7th tube support plate (TSP) handholes to assess structural condition and cleanliness, including that of TSP wedges and associated welds.
- Ultrasonic thickness measurement of selected feedring locations.
- Visual inspection of internal structures accessible from the lower inspection ports (i.e., tubesheet handholes) as well as the tube bundle periphery.

b. *Active degradation mechanisms found*

Only three tubes were identified with tube degradation during this examination. The three indications were caused by shallow volumetric tube degradation at TSP land contact points and are characteristic of TSP vibration and wear. The three indications were initially identified during the 2007 inspection of SG "A" and none have exhibited growth since the 2007 inspection (see Table 2).

c. *Nondestructive examination techniques utilized for each degradation mechanism*

The 2011 tube inspections focused on the degradation mechanisms listed in Table 1 utilizing the referenced eddy current techniques.

Table 1 – Inspection Method for Applicable Degradation Modes

Classification	Degradation Mechanism	Location	Probe Type
Potential	Tube Wear	Anti-Vibration Bars	Bobbin – Detection Bobbin and +Point™ – Sizing
Potential	Tube Wear	Flow Distribution Baffle (FDB)	Bobbin – Detection Bobbin and +Point™ – Sizing
Existing	Tube Wear	Tube Support Plate (TSP)	Bobbin – Detection Bobbin and +Point™ – Sizing
Potential	Tube Wear	Freespan & AVB tangents (Row 8, 14, 26)	Bobbin – Detection Bobbin or +Point™ – Sizing
Potential	Tube Wear (foreign objects)	Freespan, Top-of-Tubesheet (TTS), FDB, and TSP	Bobbin and +Point™ – Detection +Point™ - Sizing
Potential	Intergranular attack (IGA)/Outside Diameter Stress Corrosion cracking (ODSCC	Hot Leg TTS sludge pile critical area	Bobbin and +Point™ – Detection +Point™ - Sizing
Potential	OD Pitting	TTS sludge pile critical area	Bobbin – Detection +Point™ - Sizing
Relevant/Informational Inspection	Primary Water Stress Corrosion Cracking (PWSCC)	Hot leg TTS sludge pile critical area and within-tubesheet anomaly locations	+Point™ – Detection and Sizing
Relevant/Informational Inspection	IGA/ODSCC PWSCC	Row 1 U-bends	+Point™ – Detection and Sizing
Relevant/Informational Inspection	IGA/ODSCC	Freespan, FDB, TSP	Bobbin – Detection +Point™ - Sizing
Relevant/Informational Inspection	IGA/ODSCC	TTS outside the critical area	+Point™ – Detection and Sizing

d. *Location, orientation (if linear), and measured sizes (if available) of service induced indications*

Table 2 provides sizing information for the only tube degradation identified during the fall 2011 examination.

Table 2 – Service Induced Tube Degradation

SG	Row	Col	Location	ETSS	Axial Length (in)	Circ. Length (in)	Max Depth (%TW)	Initially Reported
A	2	25	@06C-0.53	96910.1	0.62	0.32	13	2007 (16 %TW)
A	2	91	@04C-0.52	96910.1	0.69	0.29	8	2007 (10 %TW)
A	15	9	@03H+0.45	96910.1	0.30	0.32	8	2007 (11 %TW)

In addition, two low voltage dents (<5 Volts) were not present during the previous outage examination and are consequently judged to have developed during service. Both of these new dents were identified in tube SGA R46C39 and they were located at the upper and lower edges of TSP 4C. The affected tube is adjacent to two tubes (SGA R46 C37 and SGA R46 C38) which had four new dent indications at the same location in 2007. It is noted that this group of tubes is adjacent to a TSP wedge location. The wedge may have played a role in the formation of the dents by affecting the local TSP geometry in response to the thermal expansion and contraction of SG internals. Because of the appearance of new dents in 2007 and in 2011, it is unlikely that those identified in 2011 were the result of the August 23rd seismic event. There was no evidence of change in the 2007 dents, and +Point examinations of the newly dented locations identified no tube degradation.

UT thickness measurements were taken in selected regions of the SG "A" feedring during this outage for the purpose of monitoring flow assisted corrosion (FAC) related degradation. All but one measurement exceeded the minimum design requirement of 0.350 inch by a significant margin. The minimum thickness, identified in a local area within the left side reducer extension between J-nozzles 2 and 3, was measured as 0.350 inch. As a result of this finding, a re-analysis of the allowable minimum wall thickness was performed. This analysis concluded that the allowable minimum wall thickness for localized degradation is 0.240 inch; therefore, the minimum thickness measurement is substantially greater than the minimum allowable. The average of thickness measurements taken in the left side reducer extension is 0.482 inch, indicating substantial margin to the full section minimum allowable wall thickness (0.350 inch).

Two foreign objects were identified within the hot leg channel head of SG "A." One object was found to be protruding slightly from tube SGA R29C21. This object was removed from the tube (Figure 1). Post-removal, full length bobbin probe examination, and +Point probe examination of the full tubesheet depth confirmed that the foreign object caused no tube degradation. The second object was identified lying on the bottom of the hot leg channel head bowl and was successfully removed (Figure 2). Both objects appear to have originated from the same part (Figure 3) – possibly a conduit / pipe support clamp – and are 300 series stainless steel. A visual examination of the tubesheet revealed no evidence of tube end or cladding damage.

Figure 1 – SG A Primary Side Foreign Object

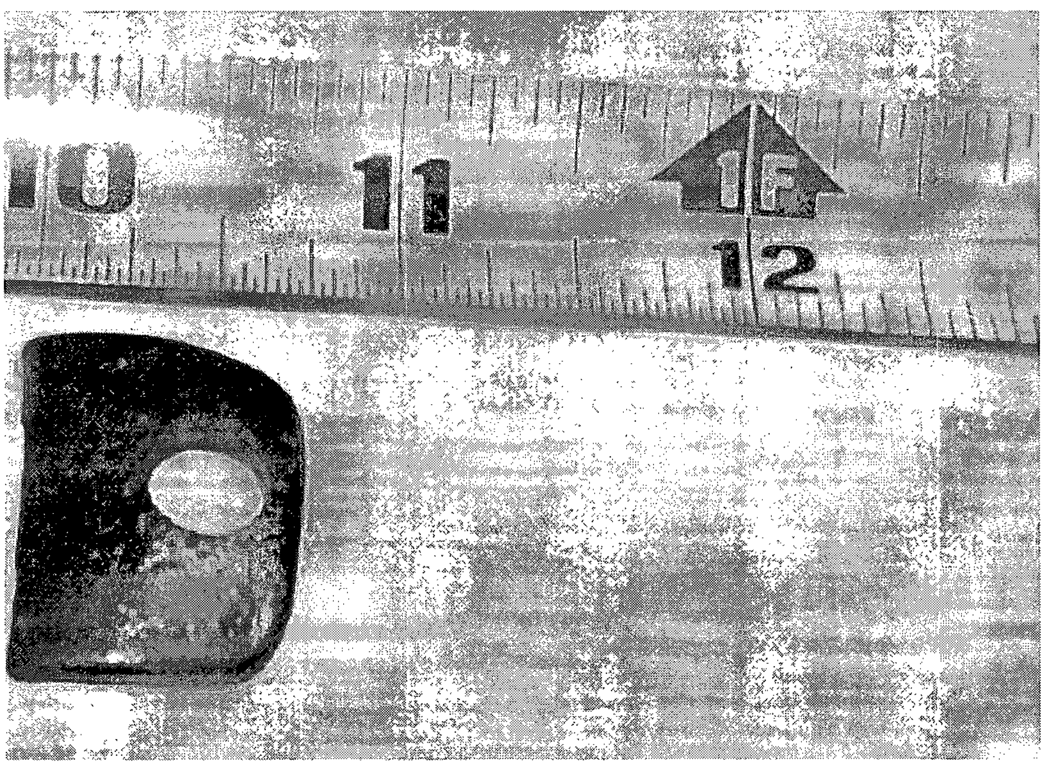


Figure 2 – SG A Primary Side Foreign Object

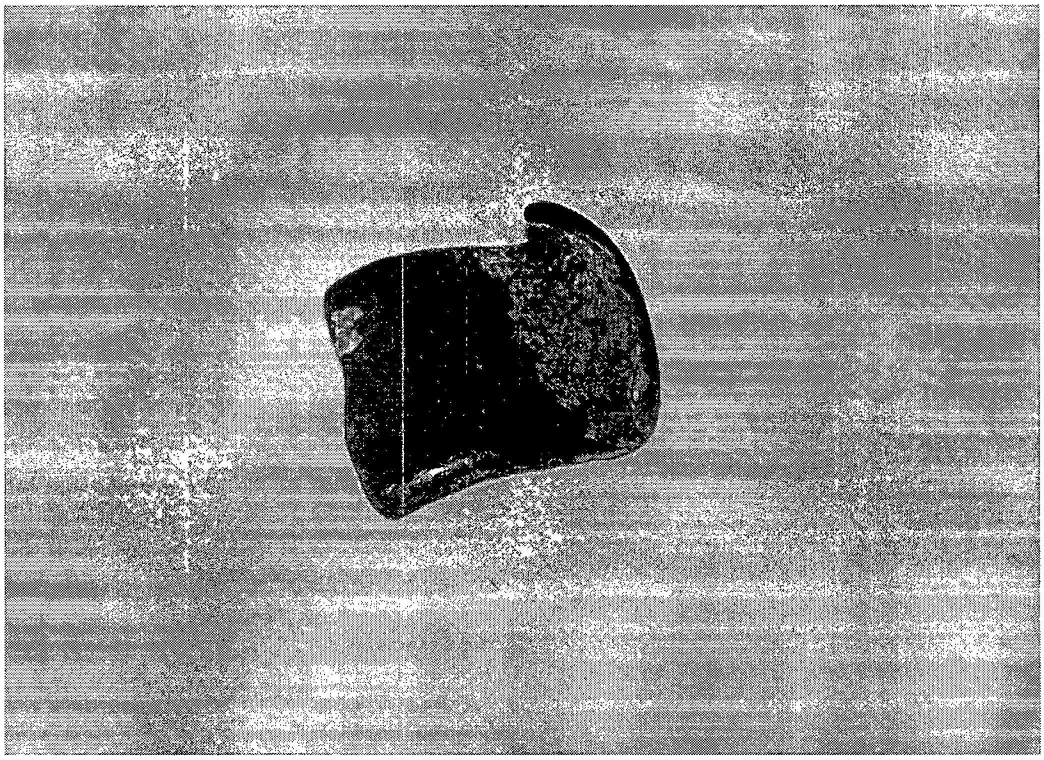
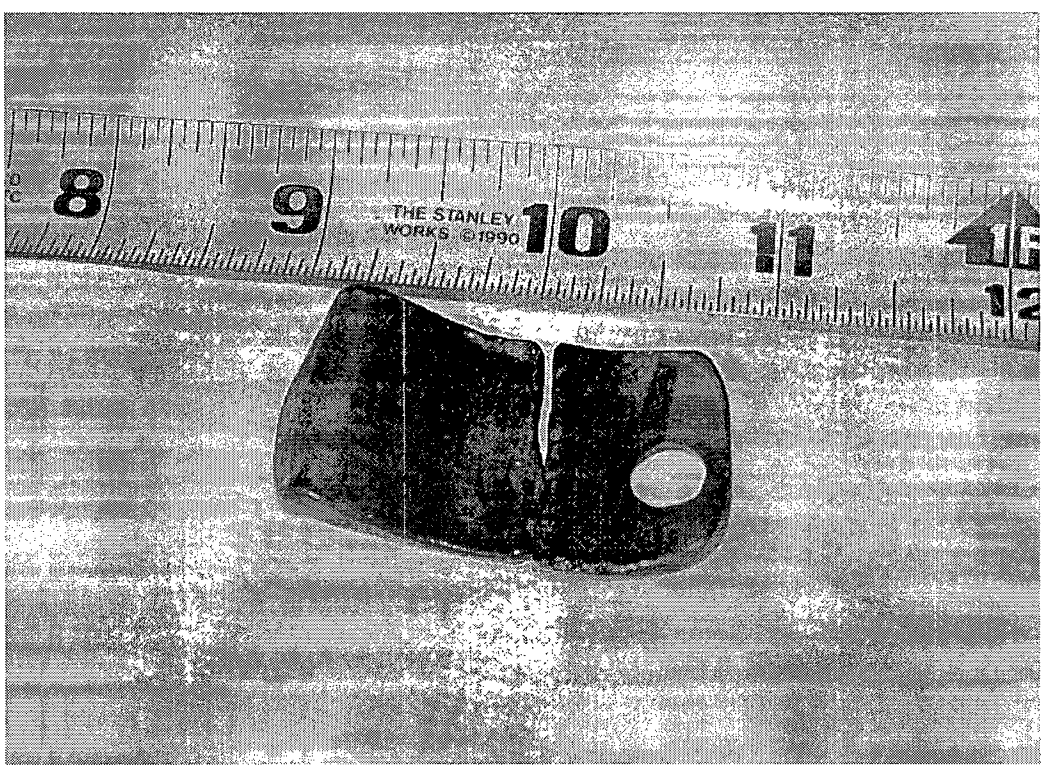


Figure 3 – SG A Primary Side Foreign Objects



e. *Number of tubes plugged during the inspection outage for each active degradation mechanism*

No tubes were plugged during this inspection.

f. *Total number and percentage of tubes plugged to date*

Table 3 summarizes the current tube plugging status for North Anna Unit 1 steam generators.

Table 3 – Current Tube Plugging Status

Steam Generator	Number of Plugged Tubes	Percent Plugged
A	0	0.00%
B	0	0.00%
C	2	0.06%
Total	2	0.02%

g. *The results of condition monitoring, including the results of tube pulls and in-situ testing*

The Condition Monitoring Assessment concluded that SG "A" did not exceed any performance criteria during the period preceding the fall 2011 inspection. No findings from the fall 2011 inspection invalidated previous operational assessments for any of the three steam generators and the condition monitoring requirements were met. Therefore, tube pulls and in-situ pressure testing were not necessary.

h. *The effective plugging percentage for all plugging in each SG*

There are no sleeves installed in the North Anna Unit 1 steam generators therefore, the effective plugging percentage remains the same as stated in (f) above.