Tennessee Valley Authority
Post Office Box 2000
Soddy Daisy, Tennessee 37384-2000

Timothy P. Cleary
Site Vice President
Sequoyah Nuclear Plant

April 14, 2009

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

In the Matter of)
Tennessee Valley Authority (TVA))

Docket No. 50-328

SEQUOYAH NUCLEAR PLANT (SQN) - UNIT 2 – STEAM GENERATOR TUBE INSPECTION INFORMATION, RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION (RAI) (TAC No. MD9595)

References:
1. NRC letter to TVA dated March 17, 2009, "Sequoyah Nuclear Plant, Unit 2-Request for Additional Information Regarding Steam Generator Tube Inservice Inspection Report For the Cycle 15 Refueling Outage (TAC No. MD9595)"
2. TVA letter to NRC dated August 27, 2008, "Sequoyah Nuclear Plant, Unit 2-Unit 2 Cycle 15 (U2C15) 90-Day Steam Generator (S/G) Report For Voltage-Based Alternate Repair Criteria And W* Alternate Repair Criteria"

This letter responds to NRC's RAI as contained in Referenced 1. The enclosure provides TVA responses to the NRC questions associated with the SG tube inspections.

There are no commitments contained in this letter.

If you have any questions about this change, please contact Beth A. Wetzel at (423)-843-7170.

Sincerely,

Timothy P. Cleary

Enclosure
cc: See page 2

cc (Enclosure):

Mr. Tracy J. Orf, Project Manager
U.S. Nuclear Regulatory Commission
Mail Stop 08G-9a
One White Flint North
11555 Rockville Pike
Rockville, Maryland 20852-2739

Mr. Lawrence E. Nanney, Director
Division of Radiological Health
Third Floor
L&C Annex
401 Church Street
Nashville, Tennessee 37243-1532

ENCLOSURE

TENNESSEE VALLEY AUTHORITY (TVA)
SEQUOYAH NUCLEAR PLANT (SQN)
UNIT 2

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION (RAI)

NRC Question 1

Please discuss the results of your foreign object search and retrieval (FOSAR). In particular, please discuss whether any loose parts (foreign objects) were left in the steam generator following FOSAR. If so, please confirm that an analysis was performed that demonstrated tube integrity would be maintained until the next steam generator tube inspection. Please discuss whether the locations where possible loose part indications (detected during the eddy current inspection) were inspected visually. If not, please discuss how the tubes near these possible loose parts were dispositioned.

TVA Response

FOSAR was performed on the top of tubesheet in each steam generator (SG) and three small pieces of foreign material were observed and removed. In SG No. 3, a small piece of wire 7/8 inch by 1/16 inch diameter was observed in the annulus and removed. In SG No. 4, a 1/2 inch by 1/8 inch piece of material (thought to be flexitalic gasket) was observed and removed. In SG No. 1, a 3/4 inch by 1/2 inch piece (thought to be weld slag material) was observed and removed. Possible loose part indications (PLPs) detected by eddy current inspection were investigated with no foreign material observed near the PLPs. Eddy current inspections did not detect any wall loss, which could be attributed to foreign material.

NRC Question 2

Please discuss the scope and results of your secondary side steam drum inspections.

TVA Response

The SQN procedure for performing SG secondary side maintenance activities requires the following when the steam drum inspections are performed.

- Visual inspection of the secondary side separator area and swirl vanes, paying special attention to the leading edge.
- Inspection of the steam dryers.
- Inspection of the steam flow transmitter penetrations to ensure they are free of debris.
- Inspection of the level transmitter penetrations to ensure they are free of debris.
- Inspection of the accessible parts below the deck plate. Ensure no debris is in the drain cups and look for orange patchy rust.
- Inspection of the feedring J-tubes, paying special attention to the wall thickness of the J-tube mouth and the J-tube to feedring weld.
- Inspection of the accessible feedwater ring supports.
- Inspection of the conical-to-upper-section girth weld on the inner shell of the SG, watching for orange patchy rust and pitting.

- Inspection of the riser barrel adjacent to J-tubes. If the flow from the J-tube impinges on the riser barrel, this area has the potential for erosion/corrosion.

A steam drum inspection was performed on SG No. 1 with no abnormalities identified.

NRC Question 3

On page 6 of 106 in your November 21, 2008 letter, you indicated under the heading "ODSCC [outside diameter stress corrosion cracking] Circumferential at HTS [top of tubesheet hot-leg]" that all axial indications met the condition monitoring performance criteria and all were stabilized and plugged. Please confirm that this was intended to read all circumferential indications met the performance criteria and were stabilized and plugged.

TVA Response

The statements under the heading "ODSCC [outside diameter stress corrosion cracking] Circumferential at HTS [top of tubesheet hot-leg]" that used "axial" should have used "circumferential".

NRC Question 4

Your condition monitoring addresses various degradation mechanisms. However, several degradation mechanisms are not discussed (e.g., axially and circumferentially-oriented outside diameter initiated stress corrosion cracking in the U-bend and at dings). Please clarify why these degradation mechanisms were not listed. (Is it because the previous operational assessment did not predict that these types of indications would be present?)

TVA Response

The Electric Power Research Institute (EPRI) Steam Generator Integrity Guidelines, Revision 2, page 7-1, states:

> "Condition monitoring (CM) involves the evaluation of inspection results at the end of the inspection interval to determine the state of the steam generator tubing for the most recent period of operation relative to structural and leakage integrity performance criteria."

Therefore, conditional monitoring is a discussion of the indications identified during an inspection and the comparison of the indications to the performance criteria. Therefore, only the degradation mechanisms identified were discussed in the Condition Monitoring Report.

NRC Question 5

For several degradation mechanisms (e.g., freespan cracking, circumferentially oriented outside diameter initiated stress corrosion cracking near the top of the hot-leg tubesheet), the number of indications projected to be present was under predicted. Please discuss whether your operational assessment methodology was modified to account for this under prediction in the number of indications.

TVA Response

The EPRI Steam Generator Integrity Assessment Guidelines, Revision 2, Section 8.1 states:

"..the fundamental OA requirement is that the projected worst case degraded tube for each existing degradation mechanism shall meet the limiting structural performance parameter with 0.95 probability at 50% confidence."

The operational assessment (OA) structural evaluation methodology used was a deterministic assessment not a probabilistic assessment; therefore the quantity of indications for each degradation mechanism was not predicted. The quantity of indications was predicted in the degradation assessment. However, for each degradation mechanism, only a single indication of conservative severity was assessed. For each degradation mechanism, the OA conservatively predicted the severity; therefore no modification to the methodology was required. The Flaw Handbook partial through-wall equation to determine the burst pressure indicates pop-through of the indication (i.e., partial through-wall going to through-wall). If the most severe indication at end of cycle (EOC) will not pop-through at three times normal operating pressure (i.e., approximately 4100 pounds per square inch [psi]) then pop-through would not occur at main steam line break (MSLB) pressure of approximately 2405 psi. If the most severe indication is not through-wall, then leakage will not occur during the accident. Therefore, the quantity of indications is not relevant for either the structural or the leakage evaluations.

NRC Question 6

Several primary water stress corrosion cracking indications were found in the U-bend region of steam generator 2. Although the inspection sample was expanded to include all of the affected tubes in steam generator 2, similar expansions were not performed in the other three steam generators. Please confirm that the operational assessment (until U2C16) for the three steam generators in which 10 percent of the potentially susceptible tubes were not inspected accounted for the potential that a flaw similar (or larger) in size to what was detected in steam generator 2 was present. If the operational assessment did not account for this potential, please discuss why (given that the previous (pre-2008) inspections in this region in all steam generators were comparable).

TVA Response

Evaluations were performed for the beginning of cycle (BOC) 16 OA using the following information. These evaluations ensured the acceptability of each SG for the next operational cycle.

Axial primary water stress corrosion cracking (PWSCC) U-bend Rows 5 through 20

The axial PWSCC identified in U-bends (Rows 5 through 20) in SG No. 2 were plugged on detection. An initial 20 percent sample inspection was performed in Rows 5 through 8 in all four SGs for this degradation mechanism. One axial indication was detected during EOC-15 examination of SG No. 2 Row 8 Column 3. Therefore, 100 percent of Rows 5 through 16 and 50 percent of Row 17 were examined in SG No. 2. No indications were observed in Rows 5 through 8 for the last two inspections (Unit 2 Cycle 13 [U2C13] or U2C14) for each of the SGs. A Monte Carlo evaluation was performed to evaluate a postulated EOC-16 flaw. The structural performance criterion for this degradation is three times normal operating pressure differential (i.e., 4185 psi). The limiting BOC flaw depth is an estimation of a worst-case flaw left in service. The BOC average depth in the OA evaluation was assumed to equal the maximum depth of the indication observed and BOC length in the OA evaluation was equal to the indication length

found. The plus point was utilized for sizing for this mechanism during the EOC-15 examination and WCAP-15128, Revision 3 sizing information was utilized in this analysis. EPRI ETSS No. 96511.2 indicates detection as low as 27 percent maximum depth. A conservative BOC-16 flaw of 57 percent average depth was assumed. The postulated BOC flaw length was 0.550 inch. The length measurement uncertainty was 0.139 inch and the depth measurement uncertainty was 7.800 percent (these values include analyst uncertainty). The EPRI Steam Generator Integrity Assessment Guidelines, Revision 2, typical growth estimates has been utilized for depth growth (lognormal depth growth average is 1.504 and depth growth standard deviation of 0.650) and length growth (lognormal length growth average is -3.220 and length growth standard deviation of 0.670). For these U-bend burst pressure calculations, the tubing yield and ultimate material properties were increased 15 percent to account for increased material strength due to the cold working the tube receives during the bending process (Steam Generator Degradation Specific Management Flaw Handbook, Section 3.1.1.4). TubeWorks calculated the 95th percentile lower limit burst pressure of 4198 psi. As stated above, one indication of this degradation mechanism was detected during the EOC-15 examinations. The indication was in-situ pressure tested at 3 times the operating pressure with zero leakage observed. This data validates the conservatism of the EOC-16 prediction.

Circumferential PWSCC U-bend Rows 5 through 20

Circumferential PWSCC were first observed in Rows 6 and 7 during the U2C12 examination. Four indications of this degradation mechanism were detected during the EOC-15 inspection. PWSCC U-bend circumferential cracking in Rows 5 through 20 were plugged on detection. An initial 20 percent sample inspection was performed in Rows 5 through 8 in all four SGs for this degradation mechanism. The sample in SG No. 2 was expanded to 100 percent of Rows 5 through 16 and 50 percent of Row 17. The structural performance criterion for this degradation is three times normal operating pressure differential (i.e., 4185 psi). For this degradation mechanism, the worst-case BOC flaw was assumed to be 55 percent degraded area (PDA) through-wall. The probability of detection curve from EPRI TR-107197, “Depth Based Structural Analysis Methods for SG Circumferential Indications,” (Figure 5-54) indicates the plus point coil has a 95 percent probability of detecting a 36 PDA flaw in explosive expansions. A circumferential flaw at the top of tubesheet is more difficult to detect than a circumferential flaw in the U-bend. The 55 percent PDA value is therefore conservative. The EPRI TR-107197 curve is based on destructive analysis, not on eddy current values; therefore, non-destructive examination (NDE) uncertainty is not added. Growth was assumed to be 9.000 percent PDA/effective full power years (EFPY), which bounds the SQN specific growth data taken over a number of inspections for Rows 1 through 4 circumferential indications. When PDA growth rate (i.e., 9.000 percent PDA/EFPY for 1.344 EFPYs) is added to the BOC flaw one could expect no larger than a 67.099 PDA indication at the EOC-16, which would have a 95th percentile lower limit burst pressure of 4223 psi. During U2C12, eight U-Bend PWSCC circumferential indications were discovered in Rows 6 in SG No. 2 and 20 indications of circumferential cracking in Row 7 were detected in SG No. 4. The worst U-bend PWSCC circumferential indication discovered in Rows 5 through 20 at SQN Unit 1 or Unit 2 was 5.520 PDA. This data validates the conservatism of the EOC-16 prediction.

NRC Question 7

One tube was detected with several indications of stress corrosion cracking near the tube end. This tube was inspected with a rotating probe because it was not fully expanded in the tubesheet region. Please confirm that all of the indications in this tube were detected in the region of the tube where the previously installed plug was expanded into the tube (i.e., the plug expansion zone). In particular, address whether the indications in this tube are attributed to the previous plugging process that this tube was exposed to or whether the stress corrosion cracking is a result of the "normal" fabrication expansion process (i.e., tack expansion). The staff notes that the mechanism responsible for cracking is important in determining which tubes are susceptible to this cracking mechanism (and therefore are required to be inspected).

TVA Response

The indications aligned with either the tube to tubesheet weld, which was expanded by size rolling prior to roll-plug installation, or aligned with the distance from the tube end where the roller expanded the plug into the tube (i.e., plug expansion zone). Therefore, TVA believes the mechanism is related to the roll-plug installation.

NRC Question 8

Regarding the one tube plugged because of the "inability to perform a rotating probe examination in the U-bend region," please discuss how it was confirmed that this tube did not have a defect. If the tube could not be inspected with a rotating probe, was an in-situ pressure test performed to confirm that the tube had adequate integrity.

TVA Response

Best effort examinations were attempted from both directions. The majority of the U-bend region was examined. Extra dose and time was expended without obtaining a complete examination (valid data) from either direction. No indication was detected in any of the collected data. TVA had no reason to believe the tube was defective but elected to plug the tube for as low as reasonably achievable in future outages. In-situ pressure testing was not performed.

NRC Question 9

Please confirm that you did not use the probability of prior cycle detection model in your assessment of tube integrity for outside diameter stress corrosion cracking at the tube support plate elevations.

TVA Response

Probability of prior cycle detection model (POPCD) was not utilized in the U2C15 refueling outage.

NRC Question 10

Tubes with indications greater than 1.5 volts that were inspected with a worn probe were re-inspected. Some of these retested tubes also had indications that were less than 1.5 volts. In these cases, the original voltage (i.e., with the worn probe) was used in your tube integrity analysis. Please discuss why this approach was used rather than using the voltage obtained from a probe that passed the probe wear check. In addition, please provide a listing of the

indications including the "worn probe" voltage and the voltage obtained from the probe that passed the probe wear check.

TVA Response

TVA utilizes the methodology for the indications greater than 75 percent of the repair limit (1.5 volts for SQN Unit 2 which has the 2-volt repair limit) approved by NRC in a correspondence between A. Marion of the Nuclear Energy Institute (NEI) and B. Sheron of the NRC dated February 9, 1996. This methodology requires that a tube, which contains an ODSCC indication greater than 1.5 volts, determined with a probe that failed calibration, be retested. The correspondence states that all of the eddy current test (ECT) data should be evaluated (not just the indications above 75 percent of the repair limit) in order to provide assurance that if indications were missed with the worn probe, they will be detected. The entire tube, including any indications with ODSCC less than 1.5 volts, is retested. Since the objective that is stated in the Marion correspondence is to identify missed indications, previous bobbin calls (PBC) identified indications are labeled as PBC. Any voltage associated with a PBC call cannot be used to infer the voltage of the ODSCC indication. Since there is no requirement for the retest of indications that are less than 75 percent of the repair criterion, the original indicated voltage is used in the integrity analysis.

Figure 4-1 in the 90-Day Report (Reference 2) shows that, for retest probe wear (RPW) indications greater than 1.5 volts, the final distorted support indication (DSI) voltage is scattered about the RPW voltage fairly uniformly. This is because a worn probe is not centered as well as a "good" probe. This means that it is possible that the test coil is sometimes closer to the side of the tube containing the flaw and the voltage will be larger. However, the converse is also true and there should be no bias in probe centering. Therefore, one would expect a statistically significant sample to exhibit negligible change in terms of the voltage bin populations. The following table identifies those tubes with RPW and the voltages from a probe that has passed the centering criteria.

SG	Row	Col	Locn	First Test	Second Test	Third Test	Good Probe Cal
1	27	48	H01	0.4V DSI	PBC(0.40)		46C
			H02	1.5V RPW	1.44V DSI		46C
	28	50	H02	1.54V RPW	0.91V DSI		46C
	41	37	H02	1.59V RPW	1.47V DSI		46C
2	3	42	H02	1.64V RPW	1.84V DSI		64H
			H04	0.58V DSI	PBC(0.38)		64H
	7	48	H01	1.53V RPW	1.12V DSI		64H
	15	89	H01	1.66V RPW	1.58V DSI		40C
	27	68	H01	1.68V RPW	1.84V DSI		40C
			H02	0.68V DSI	PBC(0.61)		40C
	30	54	H01	1.54V RPW	1.63V DSI		40C
			H02	No defect detected	0.75V DSI		40C
	30	74	H02	1.6V RPW	1.73V DSI		40C
	42	67	H06	1.66V RPW	1.76V DSI		40C

SG	Row	Col	Locn	First Test	Second Test	Third Test	Good Probe Cal
3	15	3	H01	1.53V RPW	1.45V DSI		26C
			H02	1.02V DSI	PBC(0.93)		26C
			H03	0.75V DSI	PBC(0.71)		26C
	20	28	H01	1.85V RPW	1.54V DSI		45C
			H04	1.02V DSI (imputed)	detected by RPC(1.08)		45C
	20	32	H01	2.1V RPW	1.79V DSI		45C
	23	13	H01	1.64V RPW	1.56V RPW	1.62V DSI	45C
	23	30	H01	1.51V RPW	1.33V DSI		45C
	25	8	H01	1.71V RPW	1.61V RPW	1.69V DSI	45C
	26	28	H01	1.66V RPW	1.48V DSI		45C
			H03	1.08V DSI	1.03V PBC		45C
	31	28	H01	1.8V RPW	1.53V DSI		45C
			H04	1.14V DSI	0.99V PBC		45C
	31	32	H01	1.25V DSI	1.11V PBC		45C
			H02	1.55V RPW	1.22V DSI		45C
	31	76	H01	1.55V RPW	1.24V DSI		45C
			H02	0.97V DSI	0.79V PBC		45C
			H03	0.39V DSI	PBC(0.43)		45C
	32	28	H01	1.64V RPW	1.29V DSI		45C
	43	36	H01	1.62V RPW	1.53V DSI		51C
	44	58	H01	1.75V RPW	1.32V DSI		45C
			H02	0.55V DSI	0.35V PBC		45C
			H03	1.04V DSI	2.55V PBC		45C
	44	59	H01	0.74V DSI	1.46V PBC		45C
			H02	2.15V RPW	2.07V DSI		45C

SG	Row	Col	Locn	First Test	Second Test	Third Test	Good Probe Cal
4	12	34	H02	2.72V RPW	2.78V RPW	2.77V DSI	53H
	13	48	H01	1.62V RPW	1.81V DSI		51H
			H04	0.39V DSI	0.45V PBC		51H
	14	86	H01	1.54V RPW	1.46V DSI		50H
			H02	0.72V DSI	1.05V PBC		50H
			H04	0.68V DSI	0.86V PBC		50H
	17	27	H01	1.65V RPW	1.75V RPW	1.82V DSI	53H
			H03	0.34V DSI	0.22V PBC	PBC(0.20)	53H
	20	25	H01	1.55V RPW	1.65V RPW	1.58V DSI	53H
			H02	0.45V DSI	0.55V PBC	PBC(0.60)	53H
			H06	0.35V DSI	PBC	PBC(0.32)	53H
			H07	0.23V DSI	PBC	PBC(0.23)	53H
	20	40	H01	1.96V RPW	2.03V RPW	2.02V DSI	53H
			H05	0.51V DSI	0.6V PBC	PBC(0.52)	53H
	20	46	H01	0.75V DSI	0.75V PBC		51H

SG	Row	Col	Locn	First Test	Second Test	Third Test	Good Probe Cal
			H02	1.74V RPW	1.38V DSI		51H
			H03	0.57V DSI	0.54V PBC		51H
			H06	0.62V DSI	0.83V PBC		51H
	20	69	H01	1.67V RPW	1.76V RPW	1.98V DSI	53H
			H02	0.31V DSI	0.25V PBC	PBC(0.29)	53H
	22	47	H01	0.77V DSI	0.67V PBC		51H
			H02	1.57V RPW	1.21V DSI		51H
	25	40	H01	1.85V RPW	2.12V DSI		51H
			H02	0.75V DSI	0.82V PBC		51H
	25	42	H01	1.66V RPW	1.6V RPW	1.53V DSI	53H
	26	68	H01	1.75V RPW	1.6V DSI		51H
	27	73	H02	1.97V RPW	1.96V RPW	2V DSI	53H
			H03	0.68V DSI	0.71V PBC	PBC(0.52)	53H

NRC Question 11

On page B-1 of your August 27, 2008 letter, you indicated that "The leak rates were not significantly affected by including the uncertainties in the ANL [Argonne National Laboratory] tearing model." Please clarify this sentence (e.g., was an assessment of the leak rate for this indication performed using the ANL model and were the results with and without uncertainties comparable).

TVA Response

This statement refers to the calculations performed for evaluating the leakage from the pulled tube from SG No. 4 Row 22 Column 70 from SQN Unit 2 in 2006. Details have been included in EPRI Report NP-7480-L Addendum 7 2007 Database Update.

Steam line break (SLB) leak rate analyses were performed for the SG No. 4 Row 22 Column 70 01H measured crack depth profiles. The analysis method applied the leak rate methodology for the axial PWSCC alternate repair criteria (ARC) of WCAP-15128, Revision 2. This method calculates leakage from the depth profile, accounts for potential ligament tearing up to the SLB pressure differential and uses leak rate analysis methods correlated and adjusted to measurements. Nominal leak rate calculations were performed. Since the profiles were from destructive examination results, it was not necessary to apply uncertainties to the depth profile. The methods applied the ANL ligament tearing model, as described in WCAP-15128, Revision 2, to calculate potential ligament tearing at SLB conditions. The leak rates were not significantly affected by including uncertainties (described in WCAP-15128, Revision 2) in the ANL tearing model. The ligament tearing pressure is calculated for all potential sub-lengths of the crack profile to obtain the longest crack length that would tear at SLB conditions.

NRC Question 12

In your operational assessment and condition monitoring assessment, 0.008 gallons per minute primary to secondary leakage was attributed to "all other sources." Please clarify the nature of these sources (e.g., cracking in U-bend).

TVA Response

This leakage value was included because of the possibility for other cold leg tube ends that had been previously plugged by rolled plugs and later de-plugged. The W* leakage value for a postulated crack greater than 12 inches below the top of tubesheet (0.00009 gal/ min) was multiplied by 94 (quantity of Row 1 tubes) to obtain 0.008 gal/min.

NRC Question 13

On page E2-2 of your August 27, 2008 letter, you indicated that primary water stress corrosion cracking indications at the top of the tubesheet were included in the condition monitoring W leakage evaluation regardless of whether or not they were above the bottom of the WEXTEX transition (BWT). You then indicate that: "The location of upper crack tip was subtracted for the location of the BWT and then this value had the non-destructive examination (NDE) uncertainty subtracted. If the value was negative, it was then assumed to be zero." Please clarify these last two sentences.*

TVA Response

A more accurate statement of the criteria used is, "The distance below the bottom of the BWT to the upper crack tip is determined and then the (NDE) uncertainty is subtracted. If it is determined the crack is above the BWT then the value is assumed to be zero, and included in the W* leakage calculation to ensure conservatism."

NRC Question 14

In the third paragraph on page E2-2 of your August 27, 2008 letter, you indicate that "The leakage value for the bins was summed to obtain the total in the 8 inches to 12 inches below the top of tubesheet region." Should this sentence have indicated that this was the leakage for the 0 inch to 8 inch region?

TVA Response

The sentence should have indicated that this was the leakage for the 0-inch to 8-inch region.