TXU Power
Comanche Peak Steam Electric Station
P. O. Box 1002 (E01)
Glen Rose, TX 76043
Tel: 254 897 5209
Fax: 254 897 6652
mike.blevins@txu.com

Mike Blevins
Senior Vice President &
Chief Nuclear Officer

Ref: 10 CFR 50.55a

CPSES-200601155
Log # TXX-06095

June 12, 2006

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

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION (CPSES)
DOCKET NO. 50-445
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION,
2005 STEAM GENERATOR TUBE INSPECTIONS,
TAC No. MC8621

REF:
1) TXU Power letter, logged TXX-06025, from Mike Blevins to the U. S. Nuclear Regulatory Commission; dated February 3, 2006.
2) TXU Power letter, logged TXX-06031, from Mike Blevins to the U. S. Nuclear Regulatory Commission, dated March 1, 2005.
3) TXU Power letter, logged TXX-05059, from Mike Blevins to the U. S. Nuclear Regulatory Commission, dated March 14, 2005.

Gentlemen:

By means of the letter in Reference 1, TXU Generation Company LP (TXU Power) previously submitted the 90-day post-outage report prepared pursuant to Generic Letter (GL) 95-05 "Voltage-Based Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside Diameter Stress Corrosion Cracking" for the Unit 1 Eleventh refueling outage (1RF11). By means of the letter in Reference 2, TXU Power submitted the Technical Specification 5.6.10.b twelve month report of the results of the steam generator tube inservice inspection completed during 1RF11.

Based upon questions provided by Mr. Mohan Thadani of the NRC in an email dated May 23, 2006, TXU Power hereby provides the following additional information regarding the reports of References 1 and 2. Attachment 1 to this letter contains the NRC questions and TXU Power's response immediately following each question.

A001

This communication contains no new licensing basis commitments concerning CPSES Unit 1.

Sincerely,

TXU Generation Company LP

By: TXU Generation Management Company LLC,
Its General Partner

Mike Blevins

By: Fred W. Madden
Director, Regulatory Affairs

RJK

Attachment

c - B. S. Mallett, Region IV
M. C. Thadani, NRR
Resident Inspectors, CPSES

TXU POWER
COMANCHE PEAK STEAM ELECTRIC STATION

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION
2005 STEAM GENERATOR TUBE INSPECTIONS
TAC No. MC8621
DOCKET No. 50-445

1. **Question:**
On page 5 of 41 and 17 of 41 of Enclosure 1 to your March 1, 2006 letter, you indicated that all mix residual signals were inspected with a +Point™ probe and none were confirmed to contain axial crack-like indications. However, on page 3-1 of Enclosure 1 to your February 3, 2006 letter, you indicated that only one of the tube support plate regions with a significant mixed residual signal was found to have a distorted support indication (i.e., the 1.26 volt indication in steam generator 2). Please clarify this apparent discrepancy.

TXU Response:
At Comanche Peak Unit 1, auto data screening is used for mix residual identification and results are entered directly into the data base (without editing) for special interest +Point™ testing. A 1.26V DSI was reported for this location from manual analysis. The signal was confirmed by +Point™ as axial ODSCC (0.18V +Point™ amplitude). There were no cases of confirmed axial ODSCC in mix residual signals that did not have an associated DSI report.

2. **Question:**
Seven tungsten inert gas welded sleeves were found to be collapsed during the 2005 (1RF11) inspections. You concluded (in reference 8 to Enclosure 1 to your March 1, 2006 letter) that the weld and hardroll joints will retain integrity in the event of a collapse.

Please discuss the basis for this conclusion including how you compared the severity of the collapses studied in reference 8 to the degree of collapse observed in the field. This discussion should address not only the extent of the collapse but also the proximity of the collapsed region to the joint. The staff is assuming that if a collapse is severe enough and close to the joint, it may affect the joint's structural and leakage integrity (by pulling the sleeve away from the parent tube).

TXU Response:
The issue of TIG sleeve collapse and its effect upon sleeve joint integrity was addressed in RAI responses for another plant with C-E SGs. In summary, forces acting on the weld due to pressurization of the tube to sleeve crevice sufficient to result in collapse of the sleeve wall are not sufficient to produce general yielding of the weld. The initial evaluation of this condition (ovalized sleeves) considered a laser-welded sleeve weld, which has substantially reduced weld cross sectional area and shear area compared to the TIG welds at Comanche Peak. Collapse testing performed as part of the sleeve qualification showed all welds remained leaktight. In the 2004 outage video inspection of some of the collapsed sleeves showed the sleeve flow area was reduced on one side only and the amount of restriction was less than half of the diameter. The axial length of the collapsed area does not affect the resultant axial tensile load which may be present after collapse.

Internal collapse pressures are not sufficient to result in collapse or pulling away of the sleeve from the tube in the roll expansion region. Not only is the material cold worked by the rolling process but the resultant stiffness and residual contact forces present in the roll joint will preclude sleeve collapse in the roll region.

3. **Question:**

On page 10 of 41 of Enclosure 1 to your March 1, 2006 letter, it was indicated that the upper 95% probability, 50% confidence burst pressure was determined. When assessing burst pressures against a performance criteria, normally a lower bound prediction is used since the goal is to have high probability that the tube will not burst. Please confirm that the value reported represents a lower bound prediction of the burst pressure (which would be consistent with the remainder of the discussion on this topic).

Response:

The current revision of the EPRI Tube Integrity Guideline applies probability and confidence levels of 90% and 50%, respectively. The Comanche Peak tube integrity evaluation was performed at probability and confidence levels of 95% and 50%, or slightly conservative compared to the current revision of the Tube Integrity Guideline. Use of the term "upper bound" is defined by the probability and confidence level applied to that particular evaluation. Higher confidence levels have been applied to other evaluations in the past, primarily to show available margin or relative minor variance in results by changing either the probability or confidence level.

4. **Question:**

On page 18 of 41 of Enclosure 1 to your March 1, 2006 letter, it was indicated that all tubes with sleeves in which the hot leg straight sections were inspected with either the 540 or 520 wide groove probes were inspected at H11 with a +Point™ coil. Thus, the issue (of probesnap) is not transferable to all tubes with sleeves in which the hot leg straight sections were inspected with the wide groove probes. Please clarify these statements. For example, please verify that the 540 and 520 probes were only used in tubes in rows 1 through 4 that had sleeves installed and that all other tubes with sleeves installed were inspected with a 610 probe which was inserted from the cold leg. Please confirm that the H11 intersection of all tubes inspected with a 520 and 540 probe were inspected with a +Point™ coil.

Response:

Use of reduced diameter bobbin probes could produce a dent-like signal response due to translation irregularities in the U-bend region (probesnap). Sleeved tubes in Rows 1 through 4 were inspected on the hot leg straight section from tube entry through H11 using either a 0.520 or 0.540 inch wide groove bobbin probe. All H11 intersections (all tubes and not only sleeved tubes) were inspected with a +Point™ probe as part of the large radius U-bend inspection program (+Point™ data is collected from below H11 to below C11). Sleeved tubes in Rows 5 and higher were inspected using a 0.610 inch bobbin probe from the cold leg side.

5. **Question:**
Please clarify the following statement on page 18 of 41 of Enclosure 1 to your March 1, 2006 letter: "At the 1RF09 inspection, the history review criteria looking for change in bobbin signals were performed using the first ISI [inservice inspection] of the tube. Thus, the number of dings with indications (DNI Signals) was substantially increased as confirmed DNIs often do not exhibit significant change from one inspection to the next." In particular, is this statement trying to provide a rationale for why the number of indications detected during 1RF09 may have been greater than that in future outages (i.e., it was the first time that the history review was performed using the first ISI).

Response:
The referred to statement is simply repetition of historical observations. It was originally written to explain the increase in ding ODSCC indications from 1RF08 to 1RF09. It confirms the judgment that in general, ding ODSCC is a slow growth mechanism. By comparing signals from the 1RF01 outage against 1RF09 data the presence of change is more easily observed for slow growth mechanisms.

6. **Question:**
Please clarify the following statement on page 19 of 41 concerning the axial sizing of outside diameter stress corrosion cracking (ODSCC) indications at freespan dings: "Performance evaluation of axial length sizing for ding ODSCC indications indicates that [Proprietary Information]." In particular address whether the sizing methodology was benchmarked against metallographic data or whether it involved a comparison of analyst estimates. In addition, please clarify whether the maximum depth for this indication was measured at less than 75% or whether the 75% through-wall depth was an assumption.

If the depth estimate is an assumption or the sizing is based on expert judgment (rather than benchmarked against metallographic data), please compare this indication to others that may have been in-situ pressure tested to provide additional assurance that this indication had adequate integrity.

Response:
Sizing data was compared against metallographic data from the laboratory program. The applied maximum depth of 75%TW is a judgment based on observed eddy current characteristics and destructive examination results from the laboratory program. Ding ODSCC signals of shallow depth can be grossly overestimated (with regard to depth) using the +Point™ coil due to the residual ding response, which lies in the ID plane, and can overwhelm the ODSCC component. The laboratory crack data shows that maximum depths of <70%TW retain phase angles in the ID plane for ding amplitudes less than 5V. For smaller ding amplitudes the +Point™ residual is reduced, and ODSCC approaching depths of 70%TW will produce OD phase angles. As the 1RF11 ding amplitudes were small and still produced resultant signals in the ID plane suggests that the ODSCC observed is well less than 70%TW. The maximum depth judgment is also supported by the bobbin data, which suggests shallow ODSCC depths, and is consistent with the laboratory flaw data.

7. **Question:**
In your condition monitoring and operational assessment, there does not appear to be an assessment of the leakage from installed sleeves. Please confirm that when this source of leakage is accounted for and combined with other sources of leakage (e.g., plugs and alternate repair criteria), the leakage is within your design and licensing basis limits.

Response:
Approximately 550 Alloy 800 tubesheet sleeves are in service at Comanche Peak Unit 1. The maximum number per SG of 180 is found in SG2. Per WCAP-15918 the tubesheet sleeve SLB conditions leakage allowance of 0.00086 gpm would result in only 0.15 gpm leakage. This value is insignificant compared to the allowable limit of 27.79 gpm in the faulted loop. WCAP-15918 also includes a normal operating conditions leakage contribution of 0.00054 gpm per sleeve. This suggests that normal operating conditions leakage of 0.1 gpm (144 gpd) would be expected. As no primary to secondary leakage is currently reported, any postulated SLB conditions leakage contribution is expected to be well less than 0.15 gpm.

8. **Question:**
During the 2005 tube inspections, it is the staff's understanding that the hot-leg portion of the tubes in rows 1 through 4 were inspected with either a 0.540- or 0.520-inch bobbin probe if sleeves were installed in those tubes. The use of smaller diameter probes is permitted as discussed in Section 3.c.7 of Attachment 1 to Generic Letter 95-05. In this section, it indicates that probes other than the 0.610-inch probe can be used provided that the probes and procedures have been demonstrated on a statistically significant basis to give an equivalent voltage response and detection capability when compared to the nominal-size probe. Your approach for addressing flaws in these tubes included plugging on detection of any potential flaws identified by bobbin and subsequently confirmed by rotating probe. As a result of the above approach, the ability to have an equivalent sizing method (as compared to the 0.610-inch probe) is not as important; however, the ability to detect flaws in tubes inspected with the smaller diameter probe remains an issue. Please provide the data that demonstrates the smaller diameter probe size provides an equivalent detection capability to the 0.610-inch probe for NRC review consistent with the guidance in Section 3.c.7 of Generic Letter 95-05. If the data were previously provided to the NRC, simply reference the document in which the data were provided.

Response:
Use of the 0.520 and 0.540 inch bobbin probes were evaluated prior to sleeve installation during the 2004 outage. TXU Power letter dated March 14, 2005 (Reference 3) provided TXU Power's response to a similarly worded RAI discussed during a post-1RF10 conference call with NRC staff.

In summary, 71 DSI signals were used for the wide groove probe site qualification. For both the 0.520 and 0.540 inch wide groove probes 68 of 71 DSI signals were reported. For the 0.520 inch wide groove probe the largest 0.610 inch probe basis DSI not reported was 0.33 volt; for the 0.540 inch wide groove probe the largest 0.610 inch probe basis DSI not reported was 0.51 volt. The DSI amplitudes are Comanche Peak are small compared to other units with Model D series SGs that have applied the voltage-based repair criteria per GL 95-05. At each of the last two inspections only 1 DSI greater than 1 volt has been reported. Thus the sample comparison was limited at the upper end by the largest DSI reported at the 1RF10 outage of 1.05 volts. The distribution of DSI signals selected for the site qualification included an approximately equal number of flaws in 0.10 width bins from 0.35 to 0.75 volt.

9. **Question:**

Section 5.0 of the enclosure to your February 3, 2006 letter, describes your condition monitoring assessment. Figures 5.1 through 5.4 of this section provided the voltage distributions used for computation of the probability of burst and leakage. Please discuss whether the discrete distribution in these figures (which may have been truncated/adjusted for fractional indications) were using in the condition monitoring assessment or whether the condition monitoring assessment utilized a non-truncated/adjusted distribution of indications.

Response:

Condition monitoring assessments use the as-found-distribution with size adjusted for NDE uncertainties. These distributions are not truncated or adjusted otherwise in the analysis. The fractional indications are a result of the 0.6 probability of detection and are used in operational assessments.

The Monte Carlo analysis for the condition monitoring assessment calculation predicts and uses indication trial voltages in excess of the values shown in Figure 5.1 through 5.4. The values are truncated for graphical display only by integrating the upper tail of the Monte Carlo trial results to 0.3 and 0.7 of an indication.