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PSEG
Nuclear LLC

U. S. Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555-0001

RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION (RAI)
RE: STEAM GENERATOR TUBE INSPECTIONS ANNUAL REPORT
(TAC NOS. MB8098 AND MB8099)
SALEM UNIT NOS. 1 AND 2
FACILITY OPERATING LICENSE NOS. DPR-70 AND DPR-75
DOCKET NOS. 50-272 AND 50-311

By letter dated November 12, 2003, the NRC requested additional information pertaining to steam generator (SG) tube inspections performed at the Salem Nuclear Generating Station, Unit Nos. 1 and 2, during 2002. PSEG agreed to respond to the RAI within 60 days from the date of the letter. Our response to the RAI is attached.

Should you have any questions regarding this submittal, please contact Mr. Courtney Smyth at 856-339-5298.

Sincerely,

David F. Garchow
Vice President – Engineering and
Technical Support

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JAN 0 7 2004

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Salem Unit 1

QUESTION 1

All pressurized-water reactor (PWR) licensees have committed to follow Nuclear Energy Institute (NEI) guideline NEI 97-06, "Steam Generator Program Guidelines." On page 1 of Attachment 1 to the February 27, 2003 letter, PSEG stated that Electric Power Research Institute (EPRI) guidelines, which provide detailed guidance for implementing NEI 97-06, allow utilities to deviate from specific requirements through documented technical justification for each deviation. Five exceptions were taken to the EPRI guidelines during the 2002 inspection/outage at Salem, Unit No. 1. Please summarize the technical basis for each of these exceptions and/or deviations. Discuss whether or not the five exceptions and/or deviations have been peer-reviewed, and whether or not these exceptions will be incorporated into future revisions of the guidelines. If the exceptions have been peer-reviewed, discuss the results of the peer review and whether or not these deviations will be incorporated into future revisions of the guidelines. If they have not been peer-reviewed, discuss the reasons why they have not been peer-reviewed.

Response to Question 1:

All Unit 1 deviations to Revision 5 of the EPRI PWR SG Examination guidelines were peer reviewed in accordance with station SG program procedures. The peer review concurred with the technical justifications for deviations.

Two of the deviations prepared to support the 2002 inspections have been incorporated into Revision 6 of the EPRI PWR SG Examination Guidelines and as such are no longer considered to be technical deviations.

1. Normalizing a process channel to a site-specific value to size AVB wear and
2. I-690 mechanical plug volumetric examination requirements.

Summary of Deviations and Technical Basis

1. Deviation: Voltage Normalization for bobbin coil examinations - Revision 5 requires voltage normalization to be accomplished off the prime frequency differential channel on the four 20% through wall flat-bottom holes located on the ASME standard with the peak-to-peak voltage normalized to 4 volts with the voltage scale then applied to the balance of the other frequencies. PSEG Nuclear normalizes in the above manner, however, the process channel used for reporting Anti-Vibration Bar (AVB) wear is reset to a site specific value of 5 volts.

   Technical Basis: PSEG Nuclear normalizes in the above manner, however, the process channel used for reporting AVB wear is reset to a site specific value of 5 volts. This method of normalization has been performed by PSEG since the steam generators were replaced in 1997 and thus:

   a. This method of voltage normalization ensures consistency in the reporting of AVB wear indications.

b. Voltage normalization is not considered an essential variable in the eddy current process in accordance with Sections H.2 and H.3 of Revision 5.
c. PSEG does not have a lower voltage threshold for identifying tube degradation.
d. In accordance with Revision 5 Volume 2, the basis for stating normalization requirements is not technical in nature. The sole purpose was to provide the industry with a means for comparing indications and determining if the indications at one site are similar to indications seen at other sites. The population of AVB wear indications at Salem Unit 1 is such that PSEG does not need to compare AVB data from other utilities.

2. Deviation: Exempted those contracted PSEG Level III's involved in developing the Site Specific Performance Demonstration (SSPD) from taking the SSPD Test. Revision 5 required all individuals involved in the analysis and/or resolution of plant data to participate in the formal SSPD process without exception.

   Technical Basis: This deviation is considered administrative in nature primarily due to the fact that the PSEG Level III's are not considered to be involved in the analysis or resolution of plant data. The PSEG Level III's role it to provide general oversight of the entire eddy current process. In addition, the PSEG Level III's are considered the SSPD proctors. These individuals developed the SSPD and SSPD answers. This process in itself thoroughly familiarizes the analysts with Salem conditions.

3. Deviation: Production Analyst review of overcalls (Analyst Feedback Requirements). Revision 5 requires the utility to make available and require analysts to review a sample of their overcalls. PSEG does not require production analysts to review overcalls.

   Technical Basis: It has become industry practice to instruct all analysts to scrutinize steam generator eddy current to its minimum degradation potential, instilling the conviction that any signal deemed significant by each individual analyst be brought to the attention of the resolution team. PSEG would rather production analysts err on the conservative side and let more experienced resolution analysts resolve indications that a production analyst deems potentially significant. Even though overcalls may not be retained during the resolution process, PSEG does not feel they need to go back to the individual analyst as such. Having analysts review overcalls is not done because it may give the analyst the impression that the site does not want these signals identified (called) in the future.

   The PSEG Level III monitors the entire analysis feedback process. If there is a need to discuss overcalls it is performed on an individual case-by-case basis by the PSEG Level III.

4. Deviation: Process control requirements – Revision 5 requires that process control requirements be established to assure tube degradation detection and sizing accuracy and to minimize procedural errors. One element defined in this section is to assure that the appropriate three letter codes and system categorizing associated actions are

used to convey information about observed degradation indications and steam generator conditions. PSEG process control requirements meet the intent of the guidelines, however, in some cases, different three letter codes and system categorizing actions are utilized to identify tube degradation and conditions.

Technical Basis: PSEG considers this deviation administrative in nature. PSEG has established the necessary process control requirements stipulated in Revision 5 in the SG program procedures. The use of different three letter codes and system categorizing actions are considered administrative changes.

5. Deviation: Volumetric inspection requirements for I-690 rolled plugs. Revision 5 requires volumetric examinations be performed on appropriate design tube plugs. However, Section 3.7 of Revision 5, Inspection of Second Generation Steam Generators, allows for technical justifications for relaxing plug inspection requirements for plugs produced from materials having increased corrosion resistance.

   Technical Basis: There are inconsistencies in Revision 5 of the guidelines as written. Based on the design of the tube plugs that are produced from enhanced materials (corrosion resistance), there are two different examination requirements. Regardless of design, for enhanced designed tube plugs, inspection requirements should be similar. Based on the fact that a visual examination is an acceptable alternative to the un-inspectable design tube plugs, visual examinations for those tube plugs that do permit a full volume exam are justified. Both the Westinghouse and the Framatome rolled I-690 tube plugs are produced from enhanced (corrosion resistant) materials. Based on historical volumetric examination results (no degradation detected) for I-690 Framatome rolled plugs and historical visual examinations for both Westinghouse ribbed and Framatome rolled tube plugs, the performance of a visual examination for enhanced material tube plugs is an acceptable alternative to the volumetric requirements specified.

QUESTION 2

Anti-vibration bar (AVB) wear indications were sized in 2002 using a different technique than had been used during previous inspection outages. Given the importance in sizing indications in assessing their severity and for comparison against the tube plugging limits in the TSs, please discuss what effect this new sizing method had on the depth estimates of the indications. For example, was the mean (average) size of the indications similar between the two methods? If not, why not?

Response to Question 2:

During the baseline inspection, and the two previous In-Service Inspections, AVB wear was detected and sized utilizing an absolute mix per EPRI Examination Technique Specification Sheet (ETSS) 96004.3. In an effort to obtain greater consistency in the sizing of AVB indications, for Unit 1 Refueling Outage 15 (1R15) the differential mix technique per EPRI ETSS 96004.1 was site validated and used. The differential data produces a signal that displays unique and consistent measurement points thereby eliminating the subjectivity of measurements made with the absolute technique. The use of this technique should lower the analyst variability for depth estimates.

The use of the differential method required all historical indications to be re-sized prior to the outage. The evaluation showed the differential mix amplitude method of depth sizing AVB wear performed acceptably compared to the absolute mix amplitude method. The results of this re-sizing effort concluded that the differential method seemed to undercall the indications by a small amount compared to the absolute method. A correlation was made between the two methods that assumed the depths derived from the absolute method were the truth. The Root Mean Square Error (RMSE) derived was 4.95% Through-Wall (TW) which is similar to each technique's individual performance against the truth. The error standard deviation was 3.16. In summary, the differential method correlated well with the absolute method.

QUESTION 3

On page 6 of Attachment 1 to the February 27, 2003 letter, PSEG indicated that four tubes had eddy current signatures in the 150 kHz absolute strip chart which were different than that in the general population. Three tubes were in rows 1 through 10 and a fourth tube was in a higher row in the same SG. Given the potential for eddy current testing to provide insights into locations susceptible to tube degradation and for identifying locations with degradation, please provide additional details about the nature of these signals and their potential causes.

Response to Question 3:

A review of the Salem Unit 1 Refueling Outage 14 (1R14) bobbin coil data was performed for the row 1 through 10 tubes in each steam generator to determine if a similar signature was present in the 150 kHz absolute strip charts. No tubes were found that displayed the Seabrook type eddy current signature between the 06H and 06C tube support plates. There were 3 tubes identified in SG 14 with an eddy current signature that was not similar to Seabrook, but different than the bulk of the population reviewed. The tube numbers are R4 C75, R10 C83, and R2 C85. The heat-treat signal for these tubes occurred above the second hot/cold leg tube support plates. For each of these tubes, a rather large absolute channel offset signal occurs prior to the heat treat signal. These unique signatures are present in the baseline data, have not changed and are therefore some type of signal related to manufacturing.

During the examination a tube was identified with a rather unique absolute offset signal in the u-bend region (between AVB5 and the CL tangent) of a higher row tube, R49 C54 in SG 14. This signal was present in the baseline data and has not changed therefore this is also some type of signal related to manufacturing. These four tubes in SG 14 were documented in the eddy current database with a "FFO" code that means for Future Follow-up Observation. This will ensure the condition of these tubes will be monitored during future eddy current inspections.

QUESTION 4

On page 8 of Attachment 1 to the February 27, 2003 letter, PSEG indicated that its evaluation of manufacturing anomalies was streamlined during 1R15 without jeopardizing nuclear safety. Further, it was stated that the 1R15 process emphasized screening the data for "degradation" in the primary screening channel rather than monitoring all manufacturing anomalies for change. Through this process, it was concluded that degradation in the freespan area, including any degradation as a result of manufacturing anomalies would be readily seen in this channel. Given the potential for flaws to initiate in/at/near manufacturing anomalies, please briefly discuss the technical basis for your conclusion that degradation in the freespan area can be readily seen in the primary screening channel. For example, have there been any instances where flaws were not reported in the primary screening channel but were present in other channels? If so, briefly discuss the implications to your inspection process.

If the bobbin signals from manufacturing anomalies are changing, please briefly discuss the reasons for these changes and discuss whether the bobbin coil is qualified to detect the forms of degradation that may occur at these locations.

Response to Question 4:

During the Unit 1 pre-service baseline inspection, 37,855 Manufacturing Burnish Marks (MBM) indications were identified. The criterion for reporting MBMs was very conservative for the pre-service inspection. Emphasis was placed on making sure all MBMs were identified so they can be tracked during future exams. The standard guideline for reporting MBMs during an ISI exam would require the indication to be greater than 0.5" in length, > 2 volts, and less than 90 degrees in 150 KHz absolute channel. During the Unit 1 pre-service examination, the only requirement for reporting MBMs was that the indication be present in channel 6 (150 KHz absolute).

All steam generators, regardless of tubing material, have been found to contain MBMs. MBMs have no impact on the integrity of the tubes, however, there is a concern that the presence of a MBM could mask degradation or that a MBM could be an incubation site for degradation. MBM signals are identified by bobbin coil inspection and are located randomly over the length of the tubing.

During 1R13, screening of the 150 kHz differential/absolute channels identified FSD/MBM type signals. Both MBMs and Free Span Differential (FSD) signals are the result of a light buffing of the tubes to remove small imperfections of the tubing OD. The two types of signals are analogous with the exception that the FSDs are readily discernable in the differential channels, whereas MBMs are called in the absolute channel. Resolution analysts performed historical reviews of these signals to determine if the signals had "changed" by more than 15 degrees or more than 0.5 volts since the baseline inspection. Confirmation of "change" resulted in supplemental RPC testing. Most of the MBM type signals identified did exhibit some degree of rotation (change), which was considered typical for the first cycle of operation. Only 50 tubes met the ETSS requirements for supplemental Rotating Coil (RC) testing. No anomalies or degradation were found.

During 1R14, the 150 kHz differential/absolute channels were again used to identify MBM/FSD type signals. Resolution analysts performed historical reviews of these signals to determine if the signals had "changed" by more than 15 degrees or more than 0.5 volts since the fist In-Service Inspection. Confirmation of "change" resulted in supplemental RPC testing. A total of three locations were inspected with rotating coil during 1R14 and no anomalies or degradation was found.

1R15 – Initial screening for freespan degradation was performed using the prime/quarter differential process channel rather than the quarter frequency channels. The basis for these changes in the initial screening channel were:

- Industry experience of cracking at freespan manufacturing anomalies has been limited to non-thermally treated first-generation steam generator tubing.
- The Unit 1 steam generators are considered second-generation steam generators with low operating time. No freespan degradation has been identified in any second-generation alloy 600 thermally treated (I600 TT) steam generators and most of the I600 TT units in service have many more EFPY of operating time compared to Salem Unit 1.
- PSEG has monitored freespan indications for two outages and has found no degradation.
- If degradation was present; it would be detected in the prime/quarter frequency mix channel, as this channel is a subset of the quarter frequency previously used for monitoring freespan signals. In addition, most EPRI ETSS in place utilize the prime/quarter mix to screen for tube degradation.

QUESTION 5

Loose parts have resulted in several forced shutdowns including tube ruptures. On page 8 of Attachment 1 to the February 27, 2003 letter, PSEG indicated that possible loose part indications were identified in SGs 11 and 13. Please confirm whether or not these loose parts were identified as a result of the eddy current inspection (rather than through visual inspection). The report further states these conditions were reviewed and approved by PSEG engineering. Please briefly discuss the source of these loose part indications and whether the parts were removed from the SG. If these parts have not been removed, briefly summarize your technical basis for leaving the loose parts/tubes in service.

Response to Question 5:

During 1R14, all bobbin and rotating coil data was analyzed for loose parts. Two tubes in SG 14 (R42C62 and R42C63) had possible loose part calls reported during the Hot Leg (HL) Top of Tubesheet (TTS) rotating coil inspections. No detectable wear was present in the area of the loose part calls. These tubes were re-inspected during 1R15 and no change or wear associated with a possible loose part was observed. Visual inspections identified the possible loose part (PLP) to be a small machine curl that could not be removed considering the location and condition.

During the HL TTS rotating coil eddy current examination in SG 11 and SG 13, PLP indications were identified (see list below).

SG	ROW	COLUMN	INDICATION	LOCATION
11	18	62	PLP	TSH
	19	61	PLP	TSH
	26	13	PLP	TSH
	27	13	PLP	TSH
	35	61	PLP	TSH
13	21	39	PLP	TSH
	22	39	PLP	TSH
	44	63	PLP	TSH
	45	63	PLP	TSH
	45	64	PLP	TSH

None of the PLP indications had any tube wear associated with the PLP. Rotating coil inspections were performed on the tubes adjacent to the PLP indications and none of those tubes had any evidence of wear. Based solely on eddy current, the specific source of these PLPs are not known. Since sludge lancing was not scheduled during 1R15, the secondary side of the SG was not opened for the purposes of providing visual confirmation or retrieval. Therefore, no visual exams were performed to determine if the PLP indications were actual loose parts or if they were sludge related.

The technical bases for leaving the tubes with PLP indications in-service included:

- None of the PLPs tubes or tubes adjacent to PLP tubes had indications of wear.
- Based on the location of the PLP indications in relation to secondary side flows, PSEG concluded that with the small vibration amplitude at the secondary face of the tubesheet, if tube wear were to occur, the process would be slow and would not result in significant wear during the next operational cycle.

These locations are scheduled to be visually inspected during 1R16 and, if loose parts are confirmed, retrieval attempts will be made.

QUESTION 6

Please discuss whether the experience at Salem, Unit 1, with respect to AVB wear is consistent with other Model "T" SGs (e.g., in terms of growth rates and number of tubes plugged). Provide a brief explanation for any deviations with industry trends.

Response to Question 6:

In general, steam generators with AVB wear typically experience elevated AVB wear trends in the first cycles of operation. Westinghouse has presented in at least two industry workshop/conferences (Portland Maine 2000, EPRI SIA Workshop; and July 2001 SG NDE Conference) data of AVB wear trending specifically for the Westinghouse Model F SGs. The trend data indicates that AVB wear during the initial cycles of operation can range between about 15% TW to about 27% TW per EFPY. This trend typically tapers down over a period of several cycles, and after operation approaching about 12 EFPY, AVB wear per EFPY is typically at around 5%TW.

Salem Unit 1 95th percentile AVB wear per EFPY trend data is:

1R13 - ~22% TW / EFPY
1R14 - ~18% TW / EFPY
1R15 - ~14% TW / EFPY

Salem Unit 1 Model F SGs AVB wear trending is consistent with the industry.

Utilizing the EPRI Steam Generator Degradation Database (SGDD), 13 other Model F SGs were reviewed for total tube plugging comparison to Salem Unit 1. Based on the observation of plants that reported tube plugging in the EPRI database, tube plugging in Model F SGs ranges from about 16 to 206 tubes, with the average being about 75 tubes and the 95th percentile being about 159 tubes. Salem Unit 1 current total of 70 tubes is within the observed range of total tube plugging, and less than the average of the data.

QUESTION 7

In the report, several references are made to tubesheet expansion anomalies. Please briefly discuss the nature of these anomalies, the number and locations of all the anomalies, and the scope and results from the inspections. Discuss whether or not the new anomalies detected during this outage were missed during prior inspections, or whether or not an inservice condition is causing the anomalies.

Response to Question 7:

Tubesheet anomalies include over-expansions and under expansions. The table below is a listing of Unit 1 tubesheet anomalies.

STEAM GENERATOR	ROW	COLUMN	INDICATION	LOCATION	COMMENTS
11	2	12	Over Expansion	TSC	Baseline Indication
11	9	73	Over Expansion	TSC	Baseline Indication
11	10	116	Over Expansion	TSH	Baseline Indication
11	13	36	Over Expansion	TSC	Baseline Indication
11	21	21	Over Expansion	TSH	Baseline Indication
11	46	93	Over Expansion	TSC	Baseline Indication
12	22	91	Over Expansion	TSH	Baseline Indication
12	26	23	Over Expansion	TSC	Baseline Indication
12	29	32	Over Expansion	TSC	Baseline Indication
12	32	65	Over Expansion	TSC	Baseline Indication
12	40	86	Over Expansion	TSC	Baseline Indication
13	41	42	Over Expansion	TSH	Baseline Indication
14	25	47	Under Expansion	TSH	Baseline Indication

The tubesheet anomalies are not an in-service condition. All anomalies were present in the baseline inspections.

QUESTION 8

Boron was observed on several plugs during their visual inspection. Since the plugs serve as the reactor coolant pressure boundary and potentially as the containment boundary, please summarize your technical basis for concluding that these plugs were acceptable. Discuss whether or not subsequent inspections were performed on the plugs with boron deposits.

Response to Question 8:

Visual examinations of all hot and cold leg installed tube plugs were performed during 1R15 in accordance with procedure SC.SG-TI.RCE-0002 (Q), STEAM GENERATOR TUBE PLUG VISUAL EXAMINATION. SG 14 Hot Leg (HL), tube plug 4-69, was observed as having a light coating of boron. The boron was compared to general tubesheet conditions and other plugs, and comparatively determined to have slightly more boron; therefore, it was conservatively classified as suspect and requiring additional evaluation. This tube location was plugged on the HL and Cold Leg (CL) prior to placing the SG into operation (after steam generator replacement) with welded tube plugs. To evaluate the 1R15 condition, the light coating of boron was removed from the plug and the plug location was monitored for a period of time. No leakage or additional boric acid was observed during the review period, therefore PSEG concluded that the minor boron observed on the plug was due to plug surface conditions. Variations in boron condition between plugs and areas of the tubesheet are not uncharacteristic. Boron tends to accumulate more on areas and geometry on the tubesheet where primary coolant water collected or remained for longer periods, such as tube plugs. As such, this condition was not considered service-induced degradation, a breach of the reactor coolant pressure boundary, or a condition adverse to quality. This evaluation was documented in the corrective action program.

SALEM UNIT 2

QUESTION 1a

1. **Dented/dinged locations can serve as initiations sites for axial and circumferential cracks. In addition, the ability to detect certain types of indications at these locations with a bobbin coil may be a challenge. As a result, with respect to the inspections at dented/dinged locations, please address the following:**

   a. **Please clarify the number, location, and severity of your dents/dings.**

Response to Question 1a:

Number/Location for Dents:

Salem Unit 2 has approximately 21454 dents within all four SGs. Of this population, approximately 85% (18195) are in the hot leg Tube Support Plates (TSP). About 14.5% (3168) of the dents are in the cold leg TSPs. The remaining 0.5% (91) of dents are located in the u-bends.

Severity of Dents:

The criterion for dent reporting at TSP structures is 1 volt. The criterion for dent reporting at AVB structures is 2 volts. The dent population voltage magnitudes range from 1 volt to about 50 volts in magnitude. Of the total population of dents, about 67% are 5 volts or less, and about 89% of all the dents are less than or equal to 10 volts.

Number/Location for Dings:

Salem Unit 2 has approximately 895 dings within all four SGs. Of this population, approximately 49% (435) are on the hot leg side. About 40% (356) of the dings are in the cold leg TSPs. The remaining 11% (104) of dings are located in the u-bends.

Severity of Dings:

The criterion for ding reporting is 2 volts. The ding population voltage magnitudes range from 2 volts to about 21 volts in magnitude. Of the total population of dings about 81% are 5 volts or less, and about 97% of all the dings are less than or equal to 10 volts.

QUESTION 1b

b. **Please confirm that your voltage normalization scheme for determining the size of dents is consistent with the standard industry approach (i.e., consistent with the approach developed in support of Generic Letter 95-05).**

Response to Question 1b:

The voltage normalization scheme is consistent with that described in Attachment 1 of Generic Letter 95-05. A transfer standard method of voltage normalization is used for calibration and dents/dings are reported using the prime/quarter mix channel.

QUESTION 1c

c. **Please address whether any rotating probe exams were performed at 4H? If so, what was the scope of the inspection?**

Response to Question 1c:

Rotating coil exams were not performed at 04H during outage Unit 2 Refueling Outage 12 (2R12) based on the Critical Area (C-A) technical justification found in the 2R12 degradation assessment.

During 2R11, PWSCC at dented Hot Leg (HL) TSP's were inspected under the Critical Area (C-A) requirements specified in Revision 5 of the EPRI PWR SG Examination Guidelines. Three tubes were plugged for axial PWSCC indications as identified in the table below:

SG	Tube ID	Indication	TSP Location	Bobbin Dent Voltage	RPC Voltage
21	R2C13	SAI	01H -0.21"	1.75	0.44
21	R5C8	SAI	01H +0.00"	2.01	1.11
24	R20C45	SAI	02H +0.08"	1.31	0.43

Based on these results, PWSCC at dented HL TSP's was classified as an active degradation mechanism in the 2R12 degradation assessment and were inspected under the C-A requirements of Revision 5. The defined C-A was SG specific and is described in the table below:

SG	Inspection Scope
21	100% RPC inspection ≥ 1 volt dented TSP at 01H and a 20% sample at 02H
22	20% sample RPC inspection ≥ 1 volt dented TSP at 01H
23	20% sample RPC inspection ≥ 1 volt dented TSP at 01H
24	100% RPC inspection ≥ 1 volt dented TSP at 01H and 02H and a 20% sample at 03H

Over and above Revision 5 requirements, PSEG conservatively elected to inspect 100% of the ≥ 1 volt dented TSP at 01H, 02H, and a 20% sample of 03H in all four SGs, exceeding the C-A requirements in SG 21, 22 and 23 and meeting the C-A requirements in SG 24.

During 2R12, about 3160 $\geq$ 1 volt dented TSP's intersections were inspected as part of the base scope and 186 new dents[1] were examined with a rotating coil technique. Six tubes were repaired for dented TSP ODSCC or PWSCC indications (see table below).

SG	Tube ID	Indication	TSP Location	2R12 Bobbin Dent Voltage	Damage Mechanism
21	R6C9	SAI	01H	1.68	ODSCC
21	R24C10	SAI	01H	1.67	ODSCC
22	R2C61	SAI	01H	1.56	PWSCC
22	R27C23	SCI	01H	4.08	PWSCC
23	R10C92	SAI	01H	5.15	ODSCC
24	R6C71	SAI	01H	1.31	PWSCC

Based on the fact that 2R12 tube degradation was limited to the 01H TSP and that no tube degradation was identified at 02H or 03H, inspections at 04H were not required. The tube degradation found was bound by the C-A technical justification presented in the 2R12 degradation assessment.

QUESTION 1d

d. **Discuss why rotating probe exams were not performed at dents/dings located in the portion of the tube above/beyond 7H+2.00 inches. For example, why weren't the dents/dings in the U-bend examined with a rotating probe?**

Response to Question 1d:

Inspections on Salem Unit 2 steam generators were performed prior to the inspection findings at Comanche Peak. Based on previous outage inspection results, Unit 2 has not experienced any degradation at freespan dings. During 2R12, the guidance provided in the C-A section of Revision 5 was utilized for defining the areas requiring inspection for degradation associated with freespan dings. For 2R12, examinations were limited to the HL region that encompassed the freespan region up to 07H +2.00. Any freespan dings inspected in the u-bend were considered special interest (SI) inspections based on bobbin coil results.

NOTE: As of the date of this response, the 2R13 inspections are complete and the planned base scope rotating coil inspections included examining all freespan dings in the u-bend region.

[1] New dents are > 1 volt indications that were reported during the 2R12 bobbin coil inspection at 01H, 02H and 03H that were not inspected during 2R11.

QUESTION 1e

e. **For each flaw detected during the outage, indicate whether the flaw (1) was initially found during the bobbin screening and subsequently confirmed with a rotating probe, (2) was only identified with the rotating probe, or (3) was only identified with the bobbin after the rotating probe results were available.**

Response to Question 1e:

See table below:

SG	Tube ID	Indication	TSP Location	2R12 Bobbin Dent Voltage	Damage Mechanism	Detected by Bobbin during 2R12	Detected Only by Rotating Coil	Identified by bobbin after Rotating Coil Results
21	R6C9	SAI	01H	1.68	ODSCC	No	Yes	Possibly
21	R24C10	SAI	01H	1.67	ODSCC	No	Yes	Possibly
22	R2C61	SAI	01H	1.56	PWSCC	No	Yes	Yes*
22	R27C23	SCI	01H	4.08	PWSCC	No	Yes	No
23	R10C92	SAI	01H	5.15	ODSCC	No	Yes	Possibly
24	R6C71	SAI	01H	1.31	PWSCC	No	Yes	No

*Considered a new dent that was within the C-A for the outage and therefore inspected with rotating coil. Based on historical review, this dent was not new; rather not reported during the previous outage (1.92V).

It should be noted that the expansion criteria specified in the 2R12 degradation assessment for C-A type inspections for dents/dings does not consider or credit bobbin detection.

QUESTION 1f

f. **Please discuss whether the original scope of the rotating probe examinations at the dents/dings was expanded based on the results. The staff notes that both stress and temperature effect a tube's susceptibility to stress corrosion cracking. As a result, a larger dent at a lower temperature may be as severe (from a stress corrosion cracking standpoint) as a smaller dent at a higher temperature (material properties being equal). Briefly discuss how your inspection scope accounted for this?**

Response to Question 1f:

A total of six (6) indications were detected during the HL dented TSP inspections (3 PWSCC and 3 ODSCC). All indications were limited to the first HL TSP, therefore, expansions were not required by the EPRI PWR SG Examination Guidelines or the 2R12 degradation assessment. The base scope inspections performed bounded the degradation that was detected.

During Unit 2 Refueling Outage 9 (2R9), 100% of the HL TSP locations (both dented and non-dented) were inspected with rotating coil. Inspection history from 2R9 as well as industry operating experience were used to technically justify the C-A dent/ding sampling programs. In addition to the dent inspection program described in response to question 1c, a sampling inspection strategy was implemented for examining the higher voltage dents (> 5 volts) at the higher HL TSP locations.

QUESTION 1g

g. **Briefly discuss the extent to which the bobbin probe is qualified to inspect dented/dinged regions exceeding a specific voltage threshold (e.g., 5 volts).**

Response to Question 1g:

PSEG does not consider bobbin qualified for detecting degradation at dented/dinged regions exceeding 5 volts. Therefore, the following inspection strategy is followed for performing rotating coil inspections:

- 20% sample of the ≥ 2 volt HL freespan dings (up until 2R13, the HL was considered to be the region up to 07H +2.00 inches). The inspection program is designed to ensure 100% of the HL freespan dings are inspected within a 60 Effective Full Power Months (EFPM) timeframe.
- 20% random sample of the > 5 volt HL dented TSP. The inspection program is designed to ensure 100% of the > 5 volt HL dented TSP are inspected within a 60 EFPM timeframe.

QUESTION 1h

h. **For the free span ding examinations, briefly discuss how you determined which tubes to examine. For example was it a random sample, or were all dings above 5 volts examined with a rotating probe and the remaining sample was random. Please clarify what is meant by "no anomalies were noted."**

Response to Question 1h:

PSEG inspects a random 20% sample ≥ 2 volt HL freespan dings (up until 2R13, the HL was considered to be the region up to 07H +2.00 inches). The inspection strategy is such that 100% of the ≥ 2 volt HL freespan dings would be inspected within a 60 EFPM timeframe. Therefore, a different population is inspected each outage.

Clarification of "no anomalies were noted" is that no crack like indications were reported based on the sample inspected with rotating coil.

QUESTION 1i

i. **Please describe the scope of the dent examinations given: (1) the finding of a circumferential flaw at a 4 volt dent, and your observation that dent severity and temperature play a role in SCC susceptibility; and (2) the finding of several axial flaws that were not detected by the bobbin coil probe.**

Response to Question 1i:

See responses to QUESTIONS 1c and 1e.

QUESTION 2

2. **All PWR licensees have committed to follow NEI 97-06, "Steam Generator Program Guidelines." On page 1 of Attachment 2 to the February 27, 2003 letter, PSEG stated that EPRI guidelines, which provide detailed guidance for implementing NEI 97-06, allow utilities to deviate from specific requirements through documented technical justification for each deviation. Seven exceptions were taken to the EPRI guidelines during the 2002 inspection/outage at Salem, Unit No. 2. Please summarize the technical basis for each of these exceptions/deviations. Please discuss if the seven exceptions/deviations have been peer-reviewed, and whether or not these exceptions/deviations will be incorporated into future revisions of the guidelines. If the exceptions have been peer reviewed, discuss the results of the peer review, and whether or not these deviations will be incorporated into future revisions of the guidelines. If they have not been peer- reviewed, discuss the reasons why they have not been peer-reviewed.**

Response to Question 2:

All Unit 2 deviations to Revision 5 of the EPRI PWR SG Examination Guidelines were peer reviewed in accordance with station SG program procedures. The peer review concurred with the technical justifications for deviations.

Two of the deviations prepared to support the 2002 inspections (normalizing a process channel to a site-specific value to size AVB wear, and I-690 mechanical plug volumetric examination requirements) have been incorporated into Revision 6 of the EPRI PWR SG Examination Guidelines and are no longer considered to be technical deviations.

Summary of Deviations and Technical Basis:

1. Deviation: Voltage Normalization for bobbin coil examinations - Revision 5 requires voltage normalization to be accomplished off the prime frequency differential channel on the four 20% through wall flat-bottom holes located on the ASME standard with the peak-to-peak voltage normalized to 4 volts with the voltage scale then applied to the balance of the other frequencies. PSEG Nuclear normalizes in the above manner, but resets the process channel used for reporting AVB wear to a site-specific value of 5 volts

Technical Basis: PSEG normalizes in the above manner and resets the process channel used for reporting AVB wear to site-specific value of 5 volts. This method of normalization has been performed since 2R9 and:

a. This method of voltage normalization ensures consistency in the reporting of AVB wear indications.
b. Voltage normalization is not considered an essential variable in the eddy current process in accordance with Sections H.2 and H.3 of Revision 5.
c. PSEG does not have a lower voltage threshold for identifying tube degradation.
d. In accordance with Revision 5 Volume 2, the basis for stating normalization requirements is not technical in nature. It sole purpose was to provide the industry with a means for comparing indications and determining if the indications at one site are similar to indications seen at other sites. The population of AVB wear indications at Salem Unit 2 is such that PSEG does not need to compare AVB data from other utilities.

2. Deviation: PSEG Nuclear deviated from the minimum required EDM (electro-discharge machining) notches in the rotating coil calibration standard. Revision 5 requires the rotating coil calibration standards to have the minimum electro-discharge machining notches described in section 6.2.7.1. The PSEG standards do not have the 40% ID axial and circumferential notches or the 20% OD axial notch required by the guidelines.

   Technical Basis: Many of the EPRI ETSS rotating coil techniques require calibration utilizing the 40% ID axial or 40% ID circumferential notches. The PSEG standards do not contain these notches, however, the standard does have a 20% ID axial and 20% ID circumferential notch. To justify utilizing the standard for flaw detection purposes, a comparison was made from calibration standard runs obtained from plants that have similar SG tubing size and wall thickness to Salem Unit 2 (e.g. Diablo Canyon, Beaver Valley and Sequoyah). The standards from these plants contain both the 40% ID axial/40% ID circumferential notches that are missing from the PSEG standards and the 20% ID axial/20% ID circumferential notches that were common to the compared plants. Utilizing this data, a comparison was made by calibrating on the applicable 40% notch per the EPRI ETSS and then reviewing the phase and span setting of the applicable 20% notch to validate that the Salem calibration techniques are equivalent or more conservative.

   PSEG utilizes rotating coil sizing techniques for condition monitoring (CM) and operational assessment (OA) purposes and not for leaving crack-like indications in-service. A "plug on detection" repair criteria is implemented. To justify sizing without the 20% OD notches or the 40% ID notches, a standard run from the Salem Unit 2 data from 2R11 was calibrated by applying a phase versus percent curve utilizing the 100%, 60% and 40% OD notches and the 60% and 20% ID notches available of the Salem Standards. For comparison purposes, a standard run from Sequoyah's spring 2002 outage, which contains the 20% OD and 40% ID notches, was calibrated by applying the same phase versus percent curve utilizing the 100%, 60% and 20% OD notches and the 60% and 40% ID notches. A comparison of the calibration curve tables between the two standards shows there is very little difference in the achievable curve with either of the two OD EDM notches. Also, the 40% OD notch is more readily detectable than the 20% OD notch.

Thus, for those EPRI ETSS where calibration curves require the use of a 20% OD notch, calibrating the flaw response from the 40% OD notch is judged to provide equivalent if not more consistent sizing results. In addition, many of the EPRI ETSS utilized for sizing, do not require the use of the 20% OD notch for establishing a calibration curve. Therefore, there is no technical basis for requiring this notch in the standard when employing those techniques.

Conversely, the 20% ID notch is easily detectible due to its proximity to the surface riding coils of the probe. Therefore, for those EPRI ETSS where calibration curves require the use of a 40% ID notch, calibrating the flaw response from the 20% ID notch is judged to provide equivalent if not more consistent sizing results.

Based on the information provided above, use of the existing Salem standards for rotating coil inspections were justified.

3. Deviation: PSEG deviated from the voltage normalization requirements specified in Revision 5 for bobbin examinations. For non-alternate repair criteria utilities, the guidelines state that voltage normalization shall be accomplished off the prime frequency differential channel on the four 20% TW flat bottom holes located on the ASME calibration standard, and the peak-to-peak voltage shall be normalized to 4 volts. The voltage scale shall then be applied to the balance of the frequencies. PSEG implements the alternate repair criteria (ARC) method of voltage normalization consistent with that described in Generic Letter 95-05. For this method, a "site reference standard" was sent to Westinghouse for comparison to the "mother standard". Voltage normalization was established on the mother standard in accordance with Revision 5 requirements (the prime frequency on the four 20% TW flat bottom holes was set to 4 volts peak-to-peak, save and store to all). The "site reference standard" was then examined a number of times utilizing this setup to determine a transfer voltage for the standard. The remaining Unit 2 calibration standards were then compared to the "site reference standard" to determine a standard specific voltage for normalization.

   Technical Basis: Prior to 2R10 and consistent with Revision 5 requirements, bobbin coil calibrations were performed by setting the response of the 4x20% TW ASME holes to 4 volts peak-to-peak from the 400kHz raw channel and then doing a save/store to all channels to normalize the remaining channels and frequencies. The voltages of dents were then reported from the process channel P1, a 400/100 kHz mix. This channel's response to the 4x20% TW holes would likely be on the order of 2.75 volts based on electromagnetic theory.

   In preparation for 2R10 examinations, PSEG obtained an ARC voltage normalization value for calibration standard Z14630 based on comparisons made to the Westinghouse Alternate Plugging Criteria laboratory standard. This voltage value was then compared to PSEG's bobbin guide tube standards to establish standard-specific normalization values. This normalization method commonly referred as a transfer method of correction, is similar to the alternate repair criteria method of normalization described in Revision 5.

PSEG has utilized this method of voltage normalization since 2R10 to facilitate the licensing of a Tube Support Plate (TSP) ARC for Outside Diameter Stress Corrosion Cracking should the need arise in the future. PSEG meets the intent of Revision 5 for voltage normalization, (even though we are not licensed for an ARC), based on the following reasons:

- Voltage normalization is not considered an essential variable in the eddy current process. The primary purpose for standardizing voltage normalization requirements is to provide the industry with a common method for relating magnitude of indications.
- PSEG does not have a lower voltage threshold for identifying tube degradation
- Per Revision 5, the ARC method of voltage normalization is acceptable for plants with a licensed ARC.

4. Deviation: PSEG exempted contracted PSEG Level III's involved in developing the Site Specific Performance Demonstration (SSPD) from taking the SSPD Test. Revision 5 required all individuals involved in the analysis and/or resolution of plant data to participate in the formal SSPD process without exception.

   Technical Basis: This deviation is considered administrative in nature primarily due to the fact that the PSEG Level III's are not considered to be involved in the analysis or resolution of plant data. The PSEG Level III's role is to provide general oversight of the entire eddy current process. In addition, the PSEG Level III's are considered the SSPD proctors. These individuals developed the SSPD and SSPD answers. This process in itself thoroughly familiarizes the analysts with Salem conditions.

5. Deviation: Production analyst review of overcalls (Analyst Feedback Requirements). Revision 5 requires the utility to make available and require analysts to review a sample of their overcalls. PSEG does not require production analyst to review overcalls.

   Technical Basis: It has become industry practice to instruct all analysts to scrutinize steam generator eddy current to its minimum degradation potential, instilling the conviction that any signal deemed significant by each individual analyst be brought to the attention of the resolution team. PSEG would rather production analysts err on the conservative side and let more experienced resolution analysts resolve indications that a production analyst deems potentially significant. Even though overcalls may not be kept during the resolution process, PSEG does not feel a need to go back to the individual analyst because this may give the impression that PSEG does not want these signals identified (called) in the future.

   The PSEG Level III monitors the entire analysis feedback process. If there is a need to discuss overcalls it is performed on an individual case-by-case basis by the PSEG Level III.

   Deviation: Process control requirements. Revision 5 requires that process control requirements be established to assure tube degradation detection and sizing accuracy and to minimize procedural errors. One element defined in this section is to assure that the appropriate three letter codes and system categorizing associated actions are used to convey information about observed degradation indications and steam generator conditions. PSEG process control requirements meet the intent of the guidelines, however, in some cases, different three letter codes and system categorizing actions are utilized to identify tube degradation and conditions.

Technical Basis: PSEG considers this deviation administrative in nature. PSEG has established the necessary process control requirements stipulated in Revision 5 in the SG program procedures. The use of different three letter codes and system categorizing actions are considered administrative changes.

7. Deviation: Volumetric inspection requirements for I-690 rolled plugs. Revision 5 requires volumetric examinations be performed on appropriate design tube plugs. However, Section 3.7 of Revision 5, Inspection of Second Generation Steam Generators, allows for technical justifications for relaxing plug inspection requirements for plugs produced from materials having increased corrosion resistance.

   Technical Basis: There are inconsistencies in Revision 5 of the guidelines as written. Based on the design of the tube plugs that are produced from enhanced materials (corrosion resistance) there are two different examination requirements. Regardless of design, for enhanced designed tube plugs, inspection requirements should be similar. Based on the fact that a visual examination is an acceptable alternative to the un-inspectable design tube plugs, visual examinations for those tube plugs that do permit a full volume exam are justified. Both the Westinghouse and the Framatome rolled I-690 tube plugs are produced from enhanced materials (corrosion resistance). Based on historical volumetric examination results (not degradation detected) for I-690 Framatome rolled plugs and historical visual examinations for both design (Westinghouse ribbed and Framatome rolled) tube plugs, the performance of a visual examination for enhanced material tube plugs is an acceptable alternative to the volumetric requirements specified.

QUESTION 3

3. **AVB wear indications were sized in 2002 using a different technique than had been used during previous inspection outages. Given the importance in sizing indications in assessing their severity and for comparison against the tube plugging limits in the TSs, please discuss what effect this new sizing method had on the depth estimates of the indications. For example, was the mean (average) size of the indications similar between the two methods? If not, why not?**

Response to Question 3:

Since Unit 2 Refueling Outage 9 (2R9), AVB wear has been detected and sized utilizing an absolute mix following the guidance found in EPRI ETSS 96004.3. In an effort to obtain greater consistency in the sizing of AVB indications, for 2R12 the differential mix technique per EPRI ETSS 96004.1 was site validated and used. The differential data produces a signal that displays unique and consistent measurement points thereby eliminating the subjectivity of measurements made with the absolute technique. The use of this technique should lower the analyst variability for depth estimates.

The use of the differential method required all historical indications to be re-sized prior to 2R13. This work showed the differential mix amplitude method of depth sizing AVB wear performed acceptably compared to the absolute mix amplitude method. The results of this re-sizing effort concluded that the differential method seemed to undercall the indications by a small amount compared to the absolute method. A correlation was made between the two methods that assumed the depths derived from the absolute method were the truth. The RMSE derived was 3.60 % TW which is similar to each technique's individual performance against truth. The error standard deviation was 1.99. In summary, the differential method correlated well with the absolute method.

QUESTION 4

4. **Several volumetric indications were identified at or below the expansion transition region. Two of the indications were identified with outside diameter stress corrosion cracking (ODSCC) and one with primary water stress corrosion cracking. Given a fully expanded tube, it is unlikely that ODSCC will occur "deep" in the tubesheet region. For the two tubes with indications of ODSCC, please address the position of the bottom of the expansion transition in relation to the top of the tubesheet. If the indications are below the bottom of the expansion transition, please briefly discuss the root cause of these indications. Also, did PSEG identify any ODSCC volumetric indications below the expansion transition region?**

Response to Question 4:

For reporting purposes, PSEG reports indications based on phase angle, phase relationship (rotation) between frequencies and voltage drop across those frequencies. The table below lists the OD volumetric indications reported during 2R12 at or below the top of tubesheet. All of the indications originate from the tube wall's outer surface.

SG 23	R19C26	SVI	TSH -0.45"	ODSCC
SG 23	R31C24	SVI	TSH -0.74"	ODSCC

Both OD indications are within 0.4 inches of the Bottom of the WEXTEX Transition. Based on eddy current measurement uncertainties, these indications either occur within the open crevice region or are signals caused by some type of foreign material or tubing anomaly that was present on the tube OD or between the tube and tubesheet hole that was subsequently expanded during the explosive process. There has been no change in these signals since 2R9, therefore, it is assumed the cause of these indications is not service related.

QUESTION 5:

5. **Plants with SGs of similar design have noticed both cold-leg thinning and outside diameter stress corrosion cracking to occur in the same region of the tube bundle. To effectively size an indication (for implementation of the tube plugging limits), it is important to know the cause of an eddy current indication. Discuss how you confirm the nature of degradation at the tube supports on the cold-leg side (e.g., do you perform rotating probe examinations at all these locations). Also, how is cold-leg thinning distinguished from ODSCC?**

Response to Question 5:

During 2R9, 100% of the bobbin coil reported CL thinning indications were inspected with rotating coil probes and no evidence of ODSCC occurring in the same region was found. Subsequent to 2R9, new (detected during 2R13) CL thinning indications > 20% TW depth were inspected by bobbin coil and prior CL thinning indications that display a growth rate of > 20% TW depth in one cycle of operation were inspected with rotating coil probes. Based on the rotating coil inspections performed to date in the regions of the tube bundle where Salem has observed cold-leg thinning, no crack-like indications indicative of ODSCC have been identified.

QUESTION 6

6. **Loose parts have resulted in several forced shutdowns including tube ruptures. For the tubes with loose part signals, discuss whether the presence of the parts were visually confirmed and whether the parts were removed from the SG. If the parts were not removed, summarize the technical basis for leaving these parts in service (i.e., were any potential loose part signals identified, and how were they dispositioned?)**

Response to Question 6:

All bobbin and rotating coil data were analyzed for loose parts. The following tubes were identified as possibly having foreign material on the secondary side of the steam generator.

SG	Tube ID	Indication	Location
21	R19C61	PLP	TSH
21	R30C66	PLP	TSH
22	R12C69	PLP	TSH
22	R22C32	PLP	TSH
22	R23C28	PLP	TSH
22	R30C23	PLP	TSH
22	R31C22	PLP	TSH
24	R28C55	PLP	TSH
24	R34C61	PLP	TSH
24	R34C62	PLP	TSH

None of the PLP indications had any tube wear associated with the PLP. Rotating coil inspections were performed on the tubes adjacent to the PLP indications and none of those tubes had any evidence of wear. Based solely on eddy current testing, the specific source of these PLPs is not known. Since sludge lancing was not scheduled during 2R12 the secondary side was not opened for the purpose of providing visual confirmation or retrieval. Therefore, no visual exams were performed to determine if the PLP indications were actual loose parts or if they were sludge related.

The Technical bases for leaving the tubes with PLP indications in-service included:

- None of the PLPs tubes or tubes adjacent to PLP tubes had indications of wear.
- Based on the location of the PLP indications in relation to secondary side flows, it was concluded that with the small vibration amplitude at the secondary face of the tubesheet, if tube wear were to occur, the process would be slow and would not result in significant wear during the next operational cycle.

NOTE: These locations were visually inspected during the recently completed 2R13 outage. For locations where loose parts were confirmed, retrieval was considered. In cases where retrieval efforts failed or were not possible, an engineering analysis was performed to justify continued operation for operating cycle 14.

QUESTION 7

7. **For the two tubes with previous indications of loose part wear which were preventively plugged during 2R1 2, please discuss whether the size of these indications changed with time. If the size changed, please discuss the reason for the change given the part was removed in 2R7.**

Response to Question 7:

As stated in the Annual Report, these tubes were preventatively plugged. There was no change in the size of these indications. The tubes were preventatively plugged based on the guidance provided in the EPRI Integrity Assessment Guidelines regarding extended applicability of qualified techniques. In summary, when techniques that are qualified for a particular application are extended to applications where they may not have been formally qualified, the use of those techniques are for the purpose of repair on detection and not to allow tubes to remain in-service.

QUESTION 8

8. **One of the lessons learned from the Indian Point 2 tube rupture was that noise (data quality) can affect detectability of flaws and can represent a significant condition adverse to quality (refer to Regulatory Issue Summary 2000-22). Please briefly discuss whether the noise in the U-bend region was monitored during the inspection and whether the noise levels in the U-bend region were less than the noise levels in the qualification data set for the technique used to inspect this region.**

Response to Question 8:

The inspection strategy for the small radius U-bends for the Salem 2R11 outage included a validation of the eddy current technique. The validation involved a study to determine the similarity between the EPRI specimens and Salem Unit 2 tubing relative to background noise conditions encountered when using the qualified technique. To accomplish this, the background noise levels present in both data sets were measured and evaluated. The evaluation of background noise was the focus of the report which was based on two comparisons: (1) a comparison of the noise conditions in the qualification data set to those of Salem row 2 tubes, and, (2) a comparison of the noise conditions in the Salem row 2 tubes between the mid-range and high-frequency +Point™ probes.

Additionally, the report addressed RMS values for the noise, an investigation of the performance of additional coil excitation frequencies, a noise comparison between the 2R10 and 2R11 outages, a comparison of flaws in the EPRI data set to those seen at Salem, and an evaluation of the different types of extraneous system noise encountered during the 2R11 inspection.

The following conclusions summarize the findings contained in the report:

- The background noise amplitudes and phase angles measured in the tubes were very comparable between the steam generators supporting a conclusion that all four steam generators can be treated similarly for inspection purposes.

- The background noise levels in the Salem tubes are lower for each steam generator and measurement method than that in the EPRI qualification. The Salem tubes in this study are well bounded by the EPRI data set.

- Noise RMS values show that the variability between individual tubes and steam generators is small and that the horizontal noise component is the major contributor to the variability noted. The actual signal shape and measurement result should be considered when selecting the method of calculating RMS.

- Flaw amplitudes and depths in the EPRI specimens are much higher than those flaws reported in the Salem tubes. All of the EPRI flaws are axial except one and all of the Salem flaws are circumferential. The one circumferential EPRI flaw is similar in amplitude and phase to that of the Salem flaws. The flaw-like indications reported by Salem were only confirmed by eddy current and therefore have not been proven to be true degradation.

- The faster axial and rotational probe speeds provide more consistent data in terms of digitization rates across the entire scan and are therefore recommended. Slowing the probe axial and rotational speeds did not eliminate the noise types or levels. Slowing the probe axial and rotational speeds did not improve the signal characteristics of the flaws reported in the Salem tubes. Scan direction did not improve the signal characteristics of the flaws reported in the Salem tubes.

  The 300 kHz frequency with the mid-range probe is preferred from the standpoints of low noise characteristics, smooth isometric plots and detectability of shallow outer surface flaws. The 400 kHz frequency had similar performance, however, the average noise values were always higher.

- The 600 kHz frequency with the high frequency probe produces the lowest background noise levels with the sacrifice of outer surface flaw detection. The 600 kHz frequency did not improve the signal characteristics of the ID flaws reported by the 300 kHz mid-range probe at Salem. The 800 kHz frequency was measurably noisier, produced rough isometric plots and is therefore not recommended for use.

- The 400 kHz and 300 kHz frequencies with the high frequency probe are not adequate to replace the same frequencies with the mid-range probe. They produce higher noise amplitudes and have less OD detectability.

- Lissajous and isometric plots of the EPRI and Salem tubes are comparable from the standpoint of the appearance of the background noise and associated analysis considerations.

- Probe mechanics and rotational issues are at the root of most of the noise problems that caused rejection of the data. Numerous retests were performed in an attempt to obtain good data from each tube.

This is documented in VTD 324762 and was shared with the NRC during the 2R11 combined SG/ISI Inspection.

During 2R12, no monitoring was performed during the outage. Even though the conclusion reached in VTD 324762 was that the Salem U-bend noise (data quality) was acceptable compared to that in the EPRI dataset for the mid frequency plus point coil, during 2R12 100% of the Row 2 and 20% of the Row 3 U-bends in each steam generator were inspected with a dual coil +Point™ probe. The probe contained both mid frequency and high frequency coils spaced 18" apart. No indications were reported during this inspection.

QUESTION 9

9. **Given the potential for flaws to initiate in/at/near manufacturing anomalies and/or freespan differential signals, please briefly discuss the following:**

   What constitutes a change in the bobbin signal (e.g., 0.1 volt change, phase angle change of 3 degrees, etc.)? Are the signals compared to the baseline inspection? If not, why not?

   For the criteria used to determine if a signal exhibits little or no change, briefly discuss how the criteria was determined (e.g., was test repeatability evaluated for these types of indications such that the criteria would identify a signal change when the change was greater than normal test repeatability).

Response to Question 9:

For bobbin coil freespan indications, change was based on >15 degrees phase or 0.5 volts or new indication based on the 1983 (1st ISI) data. The Unit 2 baseline data was single frequency; therefore, comparison for change is based on the first outage ISI multi-frequency data.

PSEG does not do a comparison of the current outage data to that seen during the previous outage for determining change.

PSEG change criterion is based on what was typically used in the industry at the time. Since production analysts do not have access to historical data, the resolution analysts perform all reviews for change. With the criteria used, there have been no crack-like indications reported during the special interest rotating coil inspections for those locations meeting the change criteria.

The 2R12 outage occurred prior to the Comanche Peak outage. The 2R13 inspections are now complete and the following enhancements were implemented based on lessons learned from the Comanche Peak event:

- Tighten the change criteria by lowering the phase change criterion from 15 degrees to 10 degrees compared to the 1st ISI data.
- Regardless of the actual phase or voltage change observed during 2R12, a rotating coil inspection was performed on all locations that were dispositioned during 2R12 as not meeting the bobbin coil change criterion in an attempt to validate the criterion.
- The reporting requirements were changed for the production analysts' dispositioning of both freespan and complex indications to an "I" code designator. By design, the use of an "I" code required dual party resolution concurrence (dual party independent review for change) to disposition these indications as not requiring supplemental rotating coil inspections. In addition, "I" codes also required the Independent QDA's review and concurrence for final disposition that the location did not require supplemental rotating coil inspections.

QUESTION 10

10. Since tube plugs serve as the reactor coolant pressure boundary and potentially as the containment boundary, for the plugs which were observed to be wet or had indication of boron deposits, please summarize your basis for concluding that no action was required. Please briefly discuss whether any examinations (other than visual) were performed on these plugs.

Response to Question 10:

Visual Examinations of all hot and cold leg installed tube plugs were performed during 2R12. As a result of the visual inspections, the following Westinghouse I-600 plugs with Westinghouse PIPs installed, were observed as having a light coating of boron and/or minor wetness:

SG	Location	Leg
21	R1 C77	HL
21	R1 C24	HL
22	R1 C31	HL
23	R1 C65	HL
24	R1 C13	HL
24	R1 C65	HL

The boron and wetness was compared to tubesheet conditions and other plugs, and comparatively determined to have slightly more boron and wetness; therefore they were conservatively classified as suspect and required additional evaluation. Historically, observations have shown that mechanical plugs, PAPs and PIPs can occasionally leak a slight amount of water since the seal is mechanical. Primary side water entering during SG operation may find the return path easier since the plugs are designed to seal best from primary side pressures. The primary water is heavily borated and if the leak-back is less than evaporation rates, boron deposits will form. There is much variability in deposit formation conditions, and boron deposits are not uncommon. Boron tends to accumulate more on areas and geometry on the tubesheet where primary coolant water collected or remained for longer periods, such as tube plugs. The moisture and boron observed was not excessive and can be attributed to the normal leak-back process and/or tube plug geometry conditions.

Noting whether or not the PIPs may have experienced movement was also a part of the visual inspections, as this could indicate the PIP might not have proper retention of the plug. No PIP movement was visually detected at these tube plug locations.