November 12, 2003

Mr. Roy A. Anderson
President & Chief Nuclear Officer
PSEG Nuclear, LLC - X04
Post Office Box 236
Hancocks Bridge, NJ 08038

SUBJECT: SALEM NUCLEAR GENERATING STATION, UNIT NOS. 1 AND 2, REQUEST FOR ADDITIONAL INFORMATION RE: STEAM GENERATOR TUBE INSPECTIONS ANNUAL REPORT (TAC NOS. MB8098 AND MB8099)

Dear Mr. Anderson:

By letter dated February 27, 2003, PSEG Nuclear, LLC (PSEG), submitted information pertaining to steam generator (SG) tube inspections performed at the Salem Nuclear Generating Station (Salem), Unit Nos. 1 and 2, during 2002. This information was submitted in accordance with Technical Specification 6.9.1.5.b.

The U.S. Nuclear Regulatory Commission (NRC) staff reviews the information provided in these reports consistent with its regulatory oversight role to confirm that licensees' SG tube inspection programs are in accordance with NRC regulations and industry guidelines. In addition, the NRC staff's reviews of these reports supports reviews of other types of licensee submittals, provides background information to facilitate the exchange of information with licensees conducting SG tube inspections, and provides background information for Region-based inspectors.

Based on its review of the information provided, the NRC staff has determined that additional information is needed to complete its review. We discussed the enclosed request for additional information (RAI) with your staff during a telephone call on October 9, 2003. During the call, PSEG agreed to respond to the enclosed RAI within 60 days from the date of this letter. If circumstances result in the need to revise the target date, please contact me at (301) 415-1324.

Sincerely,

/RA/

Robert J. Fretz, Project Manager, Section 2
Project Directorate I
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket Nos. 50-272 and 50-311

Enclosure: RAI

cc w/encl: See next page

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REQUEST FOR ADDITIONAL INFORMATION

REGARDING PROPOSED STEAM GENERATOR TUBE PLUGGING REPORT

SUBMITTED IN ACCORDANCE WITH TECHNICAL SPECIFICATION 6.9.1.5.b

SALEM NUCLEAR GENERATING STATION, UNIT NOS. 1 AND 2

By letter dated February 27, 2003, PSEG Nuclear, LLC (PSEG), submitted information pertaining to steam generator (SG) tube inspections performed at the Salem Nuclear Generating Station (Salem), Unit Nos. 1 and 2, during 2002. This information was submitted in accordance with Technical Specification (TS) 6.9.1.5.b. Additional information relating to the 2002 SG tube inspections was provided in letters dated May 2 and November 5, 2002, and during a telephone conference call in April 2002.

The U.S. Nuclear Regulatory Commission (NRC) staff reviews the information provided in these reports consistent with its regulatory oversight role to confirm that licensees' SG tube inspection programs are in accordance with NRC regulations and industry guidelines. In addition, the NRC staff's reviews of these reports supports reviews of other types of licensee submittals, provides background information to facilitate the exchange of information with licensees conducting SG tube inspections, and provides background information for Region-based inspectors.

Based on its review of the information provided, the NRC staff has determined that additional information is needed in order to complete its review.

Salem, Unit No. 1

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.

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?

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.

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.

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.

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

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.

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.

Salem, Unit No. 2

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.

    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).

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

    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?

    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.

    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?

    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).

    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."

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

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.

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?

4. Several volumetric indications were identified at or below the expansion transition region. Two of the indications were identified with outside diameter stress corrossion 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?

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?

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?)

7. For the two tubes with previous indications of loose part wear which were preventively plugged during 2R12, 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.

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.

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).

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.