PSEG Nuclear LLC
P.O. Box 236,, Hancocks Bridge, NJ 08038-0236

PSEG
Nuclear L.L.C.

Technical Specification 6.9.1.10

APR 30 2008

LR-N08-0089

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington DC 20555-001

Salem Nuclear Generating Station Unit 1
Facility Operating License No. DPR-70
NRC Docket No. 50-272

SUBJECT: **RAI RESPONSE, STEAM GENERATOR TUBE INSPECTION REPORT - EIGHTEENTH REFUELING OUTAGE (1R18)**

References: (1) Letter from PSEG to NRC: "Steam Generator Tube Inspection Report – Eighteenth Refueling Outage (1R18), Salem Nuclear Generating Station, Unit 1, Facility Operating License DPR-70, Docket No. 50-272", dated October 10, 2007

In Reference 1, PSEG Nuclear LLC (PSEG) submitted its Steam Generator Tube Inspection Report for Refueling Outage 1R18 (Spring 2007), consistent with the requirements of Technical Specification (TS) 6.9.1.10.

The NRC provided PSEG a Request for Additional Information (RAI) on the Reference 1 report. On April 14, 2008, PSEG and the NRC discussed the RAI to provide additional clarification. The response to the RAI is provided as an attachment to this submittal.

If you have any questions or require additional information, please do not hesitate to contact Mr. Jeff Keenan at (856) 339-5429.

Sincerely,

Christine T. Neely
Director - Regulatory Affairs

A001
NRR

APR 30 2008

Attachments (1)

C Mr. S. Collins, Administrator – Region I
U. S. Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, PA 19406

Mr. R. Ennis, Project Manager - Salem Unit 1 and Unit 2
U. S. Nuclear Regulatory Commission
Mail Stop 08B1
Washington, DC 20555-0001

USNRC Senior Resident Inspector – Salem Unit 1 and Unit 2 (X24)

Mr. P. Mulligan
Bureau of Nuclear Engineering
PO Box 415
Trenton, New Jersey 08625

REQUEST FOR ADDITIONAL INFORMATION

REGARDING STEAM GENERATOR TUBE INSPECTIONS CONDUCTED

DURING THE SPRING 2007 REFUELING OUTAGE AT

SALEM NUCLEAR GENERATING STATION, UNIT NO. 1

DOCKET NO. 50-272

By letter dated October 10, 2007 (Agency wide Documents Access and Management System (ADAMS) Accession No. ML072970094), PSEG Nuclear LLC (the licensee) submitted a report to the Nuclear Regulatory Commission (NRC) describing the results of the steam generator (SG) tube inspections conducted during the spring 2007 refueling outage (refueling outage 1R18) at Salem Nuclear Generating Station (Salem), Unit No. 1.

The Nuclear Regulatory Commission (NRC) staff has reviewed the information the licensee provided and would like to discuss the following issues to clarify the submittal.

1. You indicated that you inspected 20% of the hot-leg population of internal tubesheet over expansions (OEX) and bulges (BLG) from the top of the tubesheet (TTS) to 17 inches below the TTS. Please provide the total population of OEXs and BLGs in each SG.

PSEG Response:

The hot-leg population of internal tubesheet over expansions (OEX) and bulges (BLG) from the top of the tubesheet (TTS) to 17 inches below the TTS is as follows:

	SG 11	SG 12	SG 13	SG 14
Total BLG	74	45	58	59
Total OEX	164	82	146	97
Total BLG and OEX	238	127	204	156

2. Please discuss the scope and results of any secondary side inspections, including foreign object search and retrieval performed during the spring 2007 outage. Please discuss the extent to which visual inspections were performed at possible loose part indications identified through eddy current examinations and the results of these exams. Please discuss the extent to which loose parts were identified visually but not by eddy current examination, also, please discuss the

extent to which loose parts were identified by +Point™ coil inspection but not by bobbin coil inspection.

PSEG Response:

In each steam generator, following high volume upper bundle flush and TTS water lance, visual inspections and Foreign Object Search and Retrieval (FOSAR) were performed at the top of tubesheet. These inspections included the full length of the no tube lane (area between row 1 tube), inner bundle inspections on the HL and CL, and completely around the annulus tube areas (shell-to-tube bundle region, including periphery tubes). The annulus / periphery tubes inspection included articulating the camera angle to view into the bundle (from the annulus region) allowing inspection between the periphery tubes into the bundle. The purpose of these inspections was to identify and remove foreign material and to assess the effectiveness of the water lancing.

Eddy Current Test (ECT) data was reviewed for possible loose parts (PLP). ALL ECT PLP indications received visual examination at the tube location(s) identified via ECT. The TTS PLP visual inspections were typically performed by manipulating the visual probe on the TTS from the no tube lane (area between the row 1 tubes) to the target tube(s) {as identified by ECT} and out to the periphery. The inspections (Bobbin, +Point, and visual) did not identify any tube wear from foreign objects. All foreign objects not removed, were assessed to remain in the SGs and are not probable to cause tube wear on any tube for the remainder of plant life. The table below summarizes the inspection results, including those detected by ECT (Bobbin and/or Rotating Coil) and/or visual.

The high volume upper bundle flush and TTS water lance was capable of removing approximately 500 pounds of sludge in total from all four SGs. Visual inspections for sludge and fouling included the U-bend region, tube support plates (TSP), and TTS. The U-bend and TSP visual inspections were performed remotely and manipulating the probe on the 7th TSP, and down from the 7th TSP to the lower TSPs (down to approximately the 3rd TSP). There was no significant fouling or blockage in the U-bends or at the broached TSPs. The TTS inspections were also performed remotely, and provided that water lancing was effective at removing the majority of TTS sludge.

Loose Part Inspections

SG	Part History Coming Into Outage	SSI* 1R18	ECT 1R18	Final Result
11	Metal Turning @ TSH R23-C25 & R23-C26	Confirmed and fixed in place.	PLP with +Point, NDD with Bobbin.	Part confirmed with ECT and SSI (0.015 inch thick, 0.4 inch curl). No signs of Wear or tube damage. Attempts to remove unsuccessful (irretrievable).
	Metal Turning @ TSH R33-C27 & R32-C27	Not Confirmed	No PLP	Likely removed by sludge lancing
	Metal Turning @ TSH R9-C62	Not Confirmed	No PLP	Likely removed by sludge lancing
	Metal Turning @ TSH R18-C74	Not Confirmed	No PLP	Likely removed by sludge lancing
	No Parts identified. ECT PLP Signal only. No tube wear detected	Not Confirmed	PLP Signal with Bobbin and +Point, TSC R56-C46 & R57-C46.	No Part visually confirmed by SSI. Loose part signal still present with ECT, possibly tube scale/deposit.
	NA	Fibrous material floating in the U-bend region	No PLP	Fibrous material was irretrievable. Possibly small fibers from insulation material
12	Metal Turning @ TSH R14-C92	Not Confirmed	No PLP	Likely removed by sludge lancing
13	NA	SSI Confirmed metallic part at @ TSH R4-C17, R5-C17	PLP @ TSH R1-C17. Bobbin and +Point PLP.	Part not confirmed at R1-C17. However, part removed by SSI at R4-C17 & R5-C17. Crumbled after removal, possible sludge rock.
	NA	SSI did not confirm	Bobbin and +Point PLP @ TSH R9-C111 & 112 R10-C112.	Periphery part. PLP by ECT prior to sludge lancing. Part likely removed by sludge lancing.
	NA	Metallic Part @ TSC R58-C76	+Point PLP on tubes 57-75, 57-76, 58-75, 58-76	Small metallic object removed
14	NA	Two Opaque objects on 3rd TSP	Bobbin data review and +Point on rows 1-4 at columns 119-122, all NDD. No PLP.	Parts were irretrievable. Appears to be two non-metallic (plastic like) 1/32 inch diameter strands of approximately 4 inch lengths via visual. No PLP in ECT, noting that objects were in close proximity to tubes.

* Secondary Side Inspection, visual

3. For each refueling outage and for each SG inspection outage since the installation of your SGs, please provide the cumulative effective full power months of operation that the SGs had accumulated at the time of the outage.

PSEG Response:

The first cycle of operation following SG replacement was Cycle 13. The approximate EFPM for each cycle since SG replacement is provided below:

Cycle	Cycle Length (EFPD)	Cumulative Cycle Length (EFPM)
13	492	16.176
14	499	32.58
15	465	47.868
16	480	63.648
17	461	78.804
18	500	95.244

4. You indicated, in part, that in approximately 62 tubes you performed rotating coil inspections of dents and dings that had bobbin voltages greater than 5 volts. Please clarify whether you inspected all dents and dings greater than 5 volts in all four SGs (i.e., are all dents and dings greater than 5 volts located in 62 tubes). In particular, provide the percentage of greater than 5-volt dents and dings examined, the percentage of greater than or equal to 2-volt dents and dings in the U-bends examined, and the percentage of anti-vibration bar (AVB) wear indications examined with a rotating coil. Please confirm that all new AVB wear indications were inspected with a rotating coil.

PSEG Response:

All dents and dings greater than 5 volts are not located in the 62 tubes addressed in 1R18. The inspections performed for the 62 tubes were for defense in depth inspections as related to OE 13898. PSEG has already taken action during outage 1R16 for issues related to OE 13898 which resulted in preventative tube plugging of two (2) tubes that were deemed suspect for precursor conditions related to OE 13898. The percentage of greater than 5-volt dents and dings examined during 1R18 was approximately 1.5 % of the total population (TSH to TSC). The percentage of greater than or equal to 2-volt dents and dings in the U-bends examined was approximately 1.3% of the total population (07H to 07C). The percentage of anti-vibration bar (AVB) wear indications examined with a rotating coil was approximately 2% of all AVB wear. All new AVB wear indications were not inspected with a rotating coil; approximately 1.5% were inspected with rotating coil.

It should be noted that Salem Unit 1 has I-600 TT tubing, and in accordance with Technical Specifications 6.8.4.i, Steam Generator Program, Salem Unit 1 is currently in the second half of the first inspection period (120 EFPM). Consistent with the EPRI PWR Steam Generator Guidelines Rev 6 (section 3.3.10); during the first inspection period, examination of regions susceptible to stress corrosion cracking (for example, expansion transitions, nonstress-relieved low-row U-bends, dents, dings) may be limited to 20% of the tubes in each SG at the refueling outage nearest the midpoint of the period and an additional 20% at the refueling outage nearest the end of the period. PSEG's inspections during 1R18 and previous outages with rotating coil probes have met or exceeded the EPRI PWR Steam Generator Guidelines Rev 6 requirements. Degradation typically requiring rotating coil probes (e.g. – SCC) is not expected at Salem Unit 1 at this time, as supported by PSEG's 1R18 Degradation Assessment.

5. You indicated that none of the detected indications challenged the structural integrity performance criterion; therefore, the accident-induced leakage performance criterion is also satisfied. Although you may be able to demonstrate that you satisfied the accident- induced leakage performance criterion, such a conclusion is not supported simply because you satisfied the structural integrity performance criterion. That is, all tubes could have adequate structural integrity and the SG may not satisfy the accident-induced leakage performance criterion. Please clarify/correct your statement.

PSEG Response:

Consistent with the EPRI SG Integrity Assessment Guidelines Rev 2 (Section 9.6), and also recognizing that the only active degradation for Salem Unit 1 is AVB wear, for volumetric degradation it is appropriate to use the EPRI Flaw Handbook burst pressure equations (with appropriate uncertainties) at lower faulted differential pressures (e.g. – MSLB) to determine the degradation required for leakage to develop. Therefore, leakage integrity at a much lower faulted pressure differential is also demonstrated via satisfactory structural integrity performance criterion verification (at $3\Delta P$).

6. Please summarize the basis for your 32-percent through-wall repair criterion for wear at the AVBs. The NRC staff notes that the indication in SG 13 in row 54, column 65 at the 3rd AVB grew from 27-percent through-wall to 71-percent through-wall over two cycles. This indication exceeded your 63-percent condition monitoring limit (although the tube had adequate integrity). If one were to assume that similar growth could occur in other tubes, it would appear that a repair criterion less than 27-percent through-wall should have been implemented if the goal is to operate more than one cycle between inspections. The NRC staff also notes that although this tube had integrity it could be because the material properties of the specific tube were higher than those used during the

determination of the condition monitoring limit (and the next tube may have worse properties).

PSEG Response:

The 32-percent through-wall repair criterion for wear at the AVBs was based on the multi-cycle (cycle 19 and 20) Operational Assessment (OA) using a Monte-Carlo probabilistic analysis approach. The cycle 19 and 20 OA was performed using guidance from the recently revised EPRI SG Integrity Assessment Guidelines (IAG), Rev 2; including consideration of variability/uncertainty with material, relational, and ECT. Note that since Revision 2 of the IAG was not released prior to the 1R16 OA, no projections were made for extreme value wear depths for cycle 17 and 18 OA. That is, as part of the revision 2 changes to the IAG, a definition is now in place to quantify the "Bundle" acceptance criteria for return to service indications. For the purposes of the cycle 19 and 20 OA, acceptance criteria is now in place to quantify the impact, on the steam generator bundle probability of survival, of returning to service ALL wear scars. Typically the simplified single flaw approach (as used with the 1R16 OA) produces amply conservative results. However, the per-bundle approach (as used with the 1R18 OA) considers each wear indication left in service and is more responsive to extreme value growth rates. It explicitly captures the fact that, if more deep wear scars are left in service, there is an increasing probability that large growth rates will be matched with large BOC depths, making deep EOC flaws more likely. Hence, this approach will yield a lower repair limit for a steam generator which has a large population of flaws, particularly large %TW flaws. This OA approach resulted in the 32-percent through-wall administrative repair criterion for outage 1R18 (i.e. - plug tubes with AVB wear 33% or greater).

Past inspection results show that growth rates, in general, have become less severe with each successive inspection. This point is demonstrated below in Figures 6-1 through 6-4. These figures show that in general the overall growth rates (especially the more critical upper tail region of the curve) has shifted to the left with each successive inspection. This demonstrates that the majority of AVB wear growth is decreasing over time. Even though the trend is a decrease in growth rate, the EPRI SG Integrity Assessment Guidelines Rev 2, Section 5.2, indicates that low degradation growth rates in the last inspection should not be favored over prior cycle data with larger growth rates until an additional cycle of low growth data has been obtained for added assurance of the low growth trend. Therefore, compliance with EPRI SG Integrity Assessment Guidelines Rev 2 points to the use of the cycle 16 growth rates for the current operational assessment. Both SG13 and SG14 exhibit equivalent upper 95th percentile growth rates, yet SG13 was selected to model the growth behavior due to the better data fit in the upper tail part of the curve. For added conservatism, the SG13 cycle 16 growth rates were used to make OA projections for each of the four steam generators in cycles 19 and 20.

The probability of meeting the structural integrity requirement of a minimum burst pressure of $3\Delta P$ was calculated for each wear scar left in service after the current inspection (1R18). The resulting per-bundle probabilities of meeting 3ΔP are approximately 0.97 or more for the plugging limit implemented (plug tubes with AVB wear of 33 %TW or greater) during 1R18. With this limit, the largest wear scar left in service was 32 %TW. The number of wear scars left in service with this plugging limit is significantly less than would have been left inservice with the technical specification limit of 40 %TW. Of the 1649 wear scars detected during the 1R18 inspection, 1202 remain inservice.

In summary, the projected structural integrity probabilities exceed the required 0.95 per-bundle probability as identified in revision 2 of the IAG, demonstrating with high probability that the 3ΔP structural performance criteria will be met, for each steam generator, during the next two operating cycles.

Figure 6-1
SG11 Bobbin Depth Growth Rates

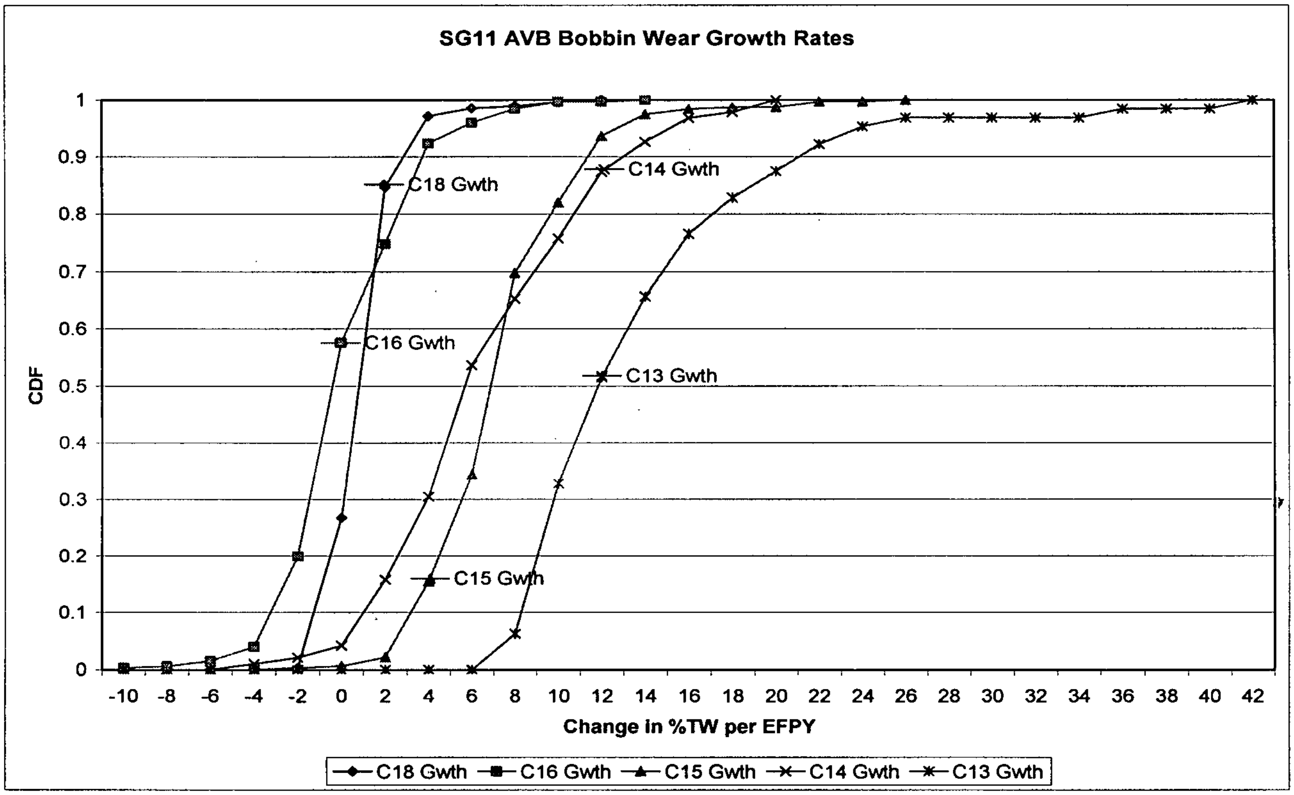


Figure 6-2
SG12 Bobbin Depth Growth Rates

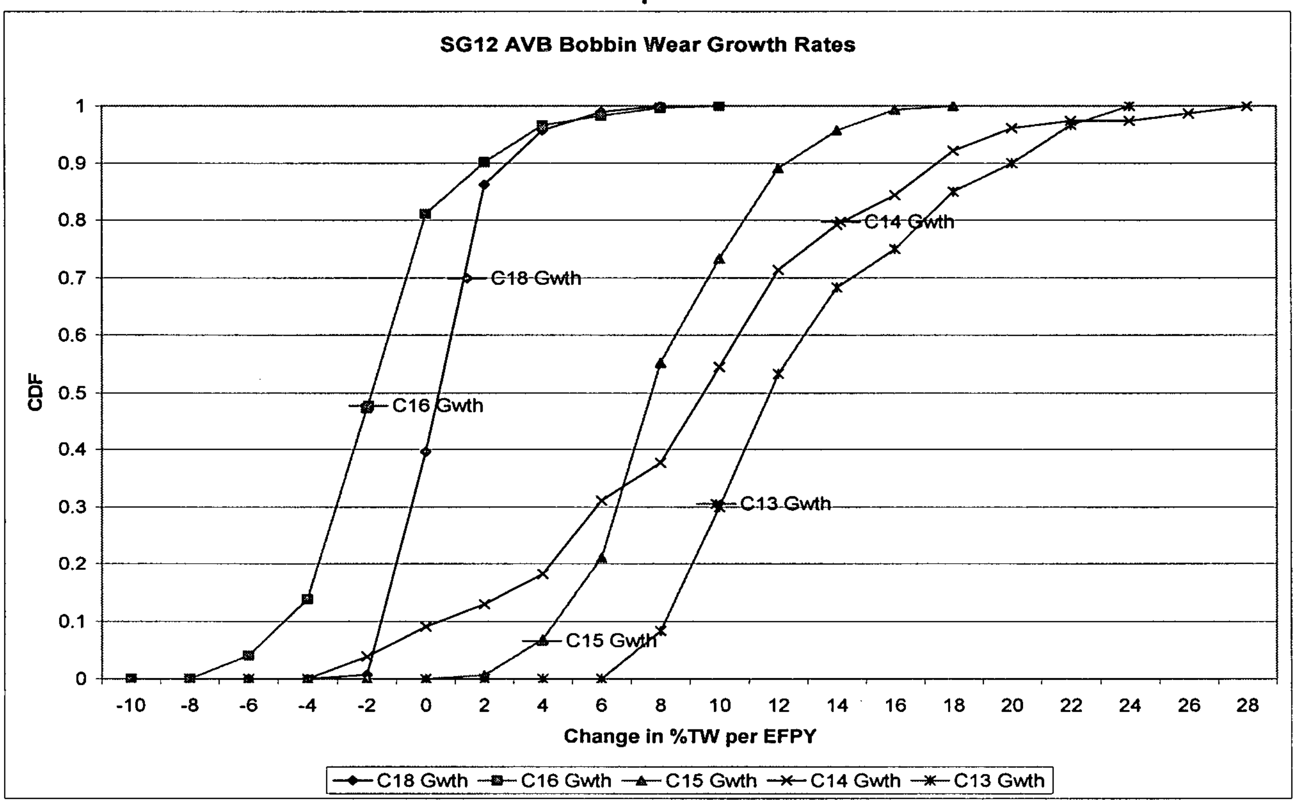


Figure 6-3
SG13 Bobbin Depth Growth Rates

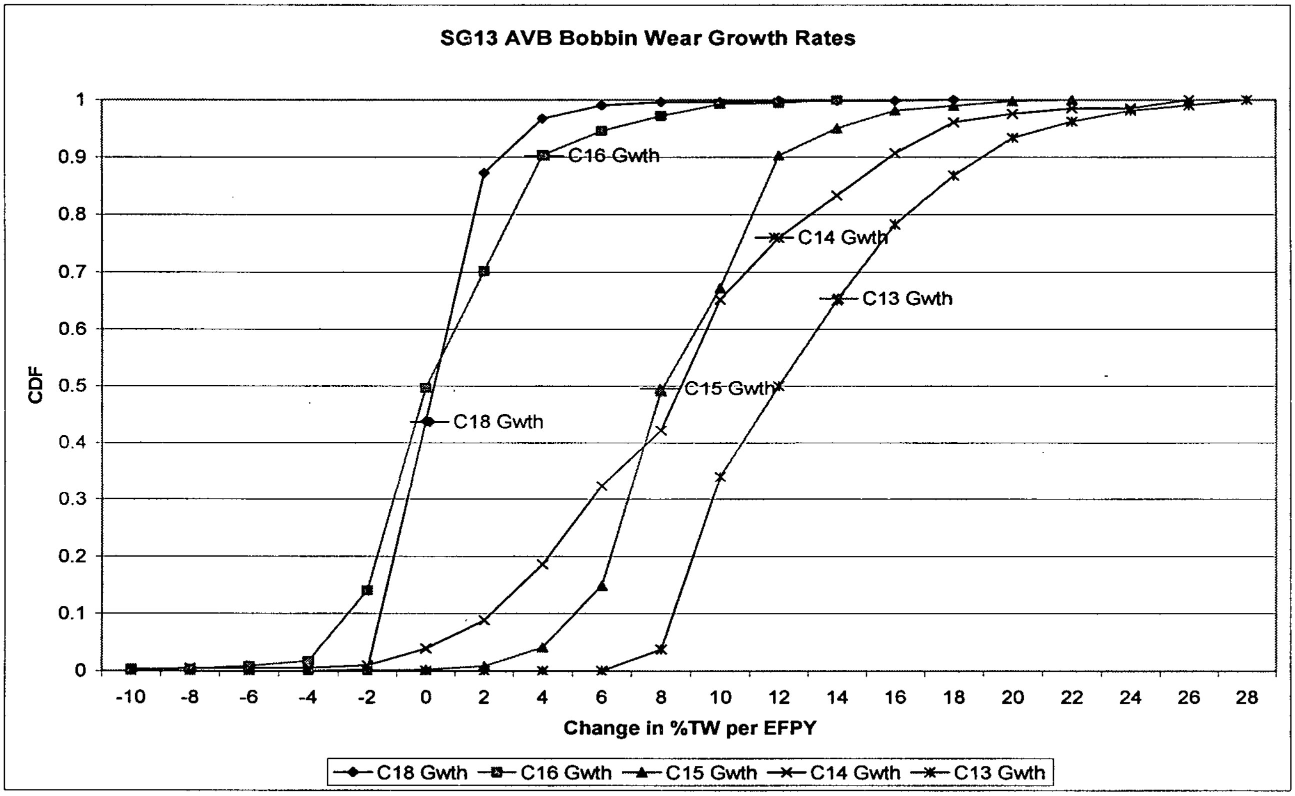
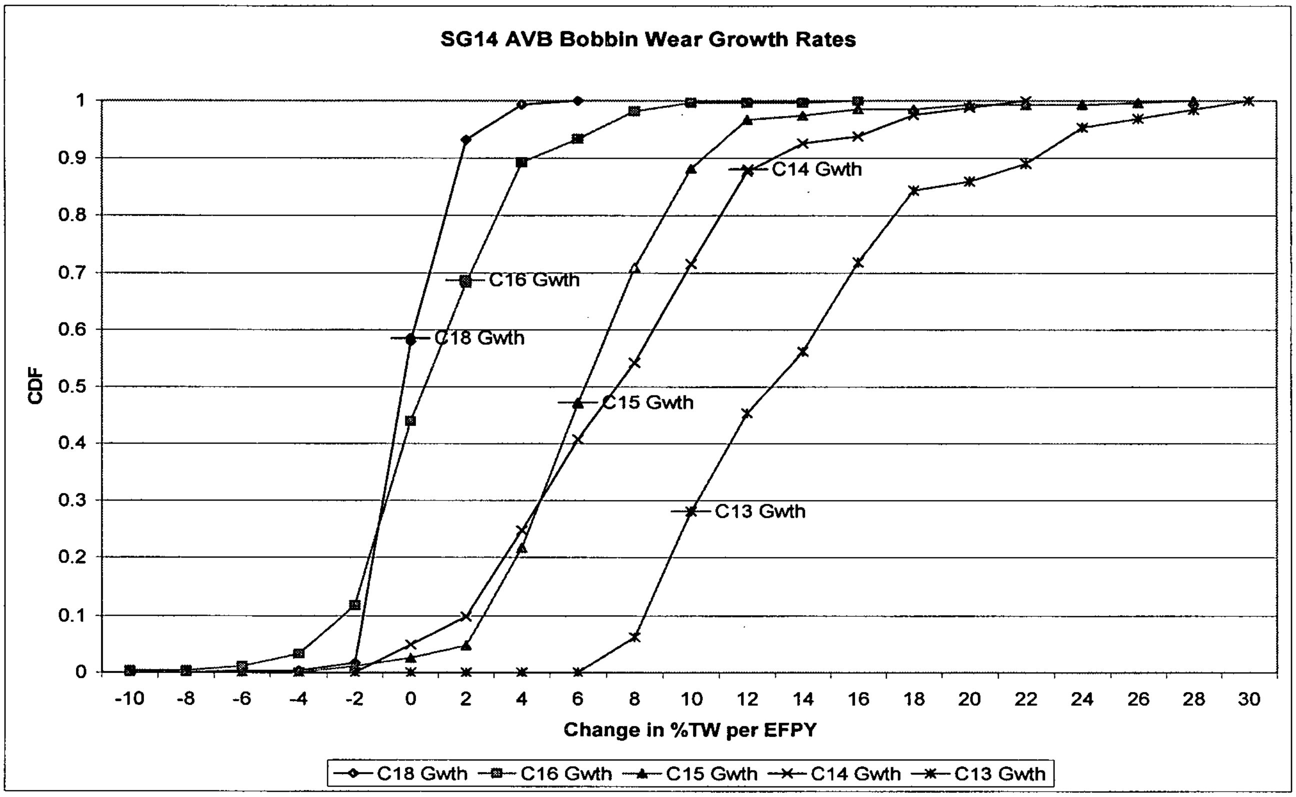


Figure 6-4
SG14 Bobbin Depth Growth Rates



7. The number of tubes plugged for AVB wear and the growth rates for these indications appear higher than for other plants with Model F SGs. Please discuss any insights on why you may have more tubes affected by wear and the higher growth rates.

PSEG Response:

In general, steam generators (particularly Westinghouse Model F SGs) 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 Structural Integrity Assessment 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 per EFPY. Salem Unit 1 AVB wear per EFPY trend data is provided in response to RAI #6. The AVB wear rate trending is consistent with other Model F SGs.

Utilizing the EPRI Steam Generator Degradation Database (SGDD), thirteen (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 for AVB wear in the EPRI SGDD database, tube plugging in Model F SGs ranges from approximately 18 to 206 tubes. Also, it should be noted that, if during outage 1R18 PSEG plugged SG tubes consistent with the Technical Specification limit of 40% TW, instead of the more conservative 33% TW (discussed in response to RAI #6), Salem Unit 1 SG total tube plugging for AVB wear would be approximately 124 tubes.

PSEG also notes that operation with the Salem replacement Model F SGs (especially in the early cycles of operation) have been under dissimilar regulatory and EPRI Guideline requirements than compared to other utilities' Model F SGs. Specifically, this is directly related to date of initial operation with the Model F SGs. Indeed, it was uncommon in the initial cycles of operation for utilities that operate Model F SGs approximately 20 years ago to perform inspections and assessments as aggressive as that performed for Salem Unit 1 Model F SGs. For example, Salem Unit 1 Model F SGs have been inspected 100% full length of the tube (via Bobbin or equivalent probe) during every planned SG inspection outage since initial operation, which PSEG believes is not consistent for the other Model F SGs being compared to in the EPRI SGDD. Furthermore, guidance such as that provided in Technical Specifications (reference TSTF-449), NEI 97-

06, and EPRI Guidelines (such as the EPRI SG Integrity Assessment Guidelines, see also response to RAI #6) did not exist for these plants at the equivalent Model F SG EFPY.