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

PSEG
Nuclear L.L.C.

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United States Nuclear Regulatory Commission
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SALEM GENERATING STATION – UNIT 1
FACILITY OPERATING LICENSE NOS. DPR-70
NRC DOCKET NO. 50-272

Subject: **License Amendment Request, Revision to Technical Specification 6.8.4.i, "Steam Generator (SG) Program," for One-Time (Interim) Alternate Repair Criteria (H*)**

References:

(1) Letter from NRC to Southern Nuclear Operating Company, Inc., "Vogtle Electric Generating Plant, Units 1 and 2, Issuance of Amendments Regarding Technical Specification (TS) Section 5.5.9, "Steam Generator Program," for Interim Alternate Repair Criteria (TAC NOS. ME1339 and ME 1340)," dated September 24, 2009

(2) Letter from D. Wright, USNRC, to M. J. Ajluni, Southern Nuclear Operating Company, Inc., "Vogtle Electric Generating Plant, Units 1 and 2, Request for Additional Information Regarding Steam Generator Program (TAC NOS. ME1339 and ME1340)", dated July 10, 2009

(3) Letter from D. Wright, USNRC, to M. J. Ajluni, Southern Nuclear Operating Company, Inc., "Vogtle Electric Generating Plant, Units 1 and 2, Request for Additional Information Regarding Steam Generator Program (TAC NOS. ME1339 and ME1340)", dated August 5, 2009

(4) Letter from NRC to PSEG: "Salem Nuclear Generating Station, Unit 1, Issuance of Amendment Re: Steam Generator Alternate Repair Criteria (TAC No. MD4034)", dated March 27, 2007

In accordance with the provisions of 10 CFR 50.90, PSEG Nuclear, LLC (PSEG) requests an amendment to the facility operating license listed above. In accordance with 10 CFR 50.91(b)(1), a copy of this request for amendment has been sent to the State of New Jersey.

The proposed amendment would modify the Salem Unit 1 Technical Specification (TS) 6.8.4.i, "Steam Generator (SG) Program," by adding a one-time alternate repair criteria that excludes portions of the tube below the top of the steam generator tubesheet from periodic

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steam generator tube inspections. In addition, this amendment request proposes to revise TS 6.9.1.10, "Steam Generator Tube Inspection Report," to provide reporting requirements specific to the alternate repair criteria. This change is supported by Westinghouse Electric Company LLC, WCAP-17071-P, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model F)." Note that the WCAP was prepared to support a permanent alternate repair criteria; the reason for the request for a one-time change is discussed below. The justification is provided in Attachment 1.

The NRC has recently granted a similar H* amendment to Vogtle Electric Generating Plant (Reference 1). To support Reference 1, References 2 and 3[1] provided a Request for Additional Information (RAI) to Southern Nuclear Operating Company (SNC) related to their application for an alternate repair criterion based on WCAP-17071-P, Revision 0. Since References 2 and 3 are applicable to the PSEG application, a response to the RAIs is also included as part of this submittal.

On September 2, 2009, in a teleconference between NRC Staff and industry personnel, NRC Staff indicated that their concerns with eccentricity of the tubesheet tube bore in normal and accident conditions (RAI question 4 of the July 10, 2009 letter and RAI question 1 of the August 5, 1009 letter) have not been completely resolved to the satisfaction of the Staff. The Staff further indicated that there was insufficient time to resolve these issues to support approval of the permanent amendment request to support upcoming refueling outages. Consequently, PSEG is proposing changes to TS 6.8.4.i and TS 6.9.1.10 be a one-time change for Unit 1 Refueling Outage 20 through the subsequent operating cycles until the next scheduled steam generator tube inspection.

Consistent with the industry, PSEG also requests that the NRC Staff provide the specific questions remaining to be resolved and that the review of the amendment request for permanent (versus one-time) alternate repair criteria continue.

WCAP-17071-P recommends the 95% probability/50% confidence H* value of 11.2 inches; however, PSEG has chosen to use an H* value of 13.1 inches for additional conservatism.

The Attachments to this letter are listed in the table below.

Attachment	Subject
1	Evaluation of the Proposed Change
2	Mark-up of Proposed Technical Specification Pages
3	Mark-up of Proposed Technical Specification Bases Pages (Information Only)

[1] The July 10, 2009, RAI letter contained twenty-four (24) questions. As a result of a teleconference with NRC staff held on July 30, 2009, Southern Nuclear Corporation (SNC) received a second request for additional information letter on August 5, 2009. The August 5, 2009 letter contained three (3) questions related to questions 4, 20 and 24 from RAI letter received on July 10, 2009. The August 5, 2009 letter also contained one (1) additional question. On August 28, 2009, SNC provided the responses to questions 1 through 24 of the July 10, 2009 letter and questions 1 through 4 of the August 5, 2009 letter.

Attachment	Subject
4	WCAP-17071-P, H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model F) (Proprietary),
5	WCAP-17071-NP, H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model F) (Non-proprietary)
6	Westinghouse affidavit letter CAW-09-2567, conforming to the provisions of 10CFR2.390 for withholding the proprietary WCAP Report
7	Westinghouse letter LTR-SGMP-09-100 P-Attachment, Response to NRC Request for Additional Information on H*; Model F and Model D5 Steam Generator (questions 1 through 20 and 24 of the Reference 2 RAI) (Proprietary)
8	Westinghouse letter LTR-SGMP-09-100 NP-Attachment, Response to NRC Request for Additional Information on H*; Model F and Model D5 Steam Generator (questions 1 through 20 and 24 of the Reference 2 RAI) (Non-proprietary)
9	Westinghouse affidavit letter CAW-09-2633, conforming to the provisions of 10CFR2.390 for withholding the proprietary RAI Responses (LTR-SGMP-09-100 P-Attachment)
10	Salem Unit 1 site specific response to (Industry) RAI questions 21, 22, and 23
11	Westinghouse letter LTR-SGMP-09-109 P-Attachment, Response to NRC Request for Additional Information on H*; RAI #4; Model F and Model D5 Steam Generators (Proprietary)
12	Westinghouse letter LTR-SGMP-09-109 NP-Attachment, Response to NRC Request for Additional Information on H*; RAI #4; Model F and Model D5 Steam Generators (Non-proprietary)
13	Westinghouse affidavit letter CAW-09-2660, conforming to the provisions of 10CFR2.390 for withholding the proprietary RAI Responses (LTR-SGMP-09-109 P-Attachment)
14	Westinghouse letter LTR-SGMP-09-121,Replacements for Illegible Pages in Prior RAI Response (LTR-SGMP-09-100)
15	Westinghouse letter LTR-RCPL-09-131, WCAP-17071-P, Rev. 0 Proprietary Information Clarification
16	Westinghouse Letter LTR-SGMP-09-144, Correction to WCAP-17071-P, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model F)"
17	List of Regulatory Commitments

Attachment 17 lists the formal regulatory commitments pending NRC approval of the proposed amendment: (1) PSEG commits to monitor for tube slippage as part of the steam generator tube inspection program, (2) PSEG commits to perform a one-time verification of the tube expansion to locate any significant deviations in the distance from the top of the tubesheet to the bottom of the expansion transition (BET). If any deviations are found, the condition will be entered into the corrective action program and dispositioned. Additionally,

PSEG commits to notify the NRC of significant deviations, and (3) PSEG commits to using the site specific leakage factor for integrity assessments.

PSEG requests approval of this change by March 30, 2010 to support Salem Generating Station Unit 1 Refueling Outage 1R20. The implementation period will be concurrent with completion of the 1R20 outage.

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

I declare under penalty of perjury that the foregoing is true and correct.

Executed on 10/08/09
(Date)

Sincerely,

Robert C. Braun
Station Vice President
Salem Generating Station

Attachments (17)

S. Collins, Regional Administrator - NRC Region I
R. Ennis, Project Manager - USNRC
NRC Senior Resident Inspector – Salem Unit 1 and Unit 2
P. Mulligan, Manager IV, NJBNE
Commitment Coordinator – Salem
PSEG Commitment Coordinator – Corporate

License Amendment Request, Revision to Technical Specification 6.8.4.i, "Steam Generator (SG) Program," for One-Time (Interim) Alternate Repair Criteria (H*)

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ATTACHMENT 1

EVALUATION

1.0 DESCRIPTION

PSEG Nuclear, LLC (PSEG) proposes to revise Salem Unit 1 Technical Specification (TS) 6.8.4.i, "Steam Generator (SG) Program," by adding a one-time alternate repair criteria excluding portions of the tube below the top of the steam generator tubesheet from periodic steam generator tube inspections. In addition, this amendment request proposes to revise TS 6.9.1.10, "Steam Generator Tube Inspection Report," to provide reporting requirements specific to the alternate repair criteria. This change is supported by Westinghouse Electric Company LLC, WCAP-17071-P, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model F), April 2009 (Reference 1)[1,2]." Note that the WCAP was prepared to support a permanent alternate repair criteria; the reason and justification for the request for a one-time change is discussed below.

The NRC has recently granted a similar H* amendment to Vogtle Electric Generating Plant (Reference 8). To support Reference 8, References 9 and 10[3] provided a Request for Additional Information (RAI) to Southern Nuclear Operating Company (SNC) related to their application for an alternate repair criterion based on WCAP-17071-P, Revision 0. Since References 9 and 10 are applicable to the PSEG application, a response to the RAIs is also included as part of this submittal.

On September 2, 2009, in a teleconference between NRC Staff and industry personnel, NRC Staff indicated that their concerns with eccentricity of the tubesheet tube bore in normal and accident conditions (RAI question 4 of the July 10, 2009 letter and RAI question 1 of the August 5, 1009 letter) have not been completely resolved to the satisfaction of the Staff. The Staff further indicated that there was insufficient time to resolve these issues to support approval of the permanent amendment request to support upcoming refueling outages. Consequently, PSEG is proposing changes to TS 6.8.4.i and TS 6.9.1.10 be a one-time change for Unit 1 Refueling Outage 20 through the subsequent operating cycles until the next scheduled steam generator tube inspection.

Consistent with the industry, PSEG also requests that the NRC Staff provide the specific questions remaining to be resolved and that the review of the amendment request for permanent (versus one-time) alternate repair criteria continue.

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1 Reference to WCAP -17071 throughout this submittal includes not only the originally issued WCAP but also all changes to the WCAP documented by the response to the Reference 9 and 10 RAIs (Attachments 7, 10 and 11).

2 All References listed in Attachment 1 are provided in Section 7.0 of Attachment 1

3 The July 10, 2009, RAI letter contained twenty-four (24) questions. As a result of a teleconference with NRC staff held on July 30, 2009, SNC received a second request for additional information letter on August 5, 2009. The August 5, 2009 letter contained three (3) questions related to questions 4, 20 and 24 from RAI letter received on July 10, 2009. The August 5, 2009 letter also contained one (1) additional question. On August 28, 2009, SNC provided the responses to questions 1 through 24 of the July 10, 2009 letter and questions 1 through 4 of the August 5, 2009 letter.

The H* analysis is based on maintaining structural and leakage integrity in the event of an accident. From a structural perspective, the 13.1 inch value of H* ensures that tube rupture or tube pull out from the tubesheet will not occur in the event of an accident in the entire life of the plant. Even in the event that all tubes in the steam generator have a 360 degree sever at 13.1 inches, structural integrity of the steam generator tube bundle will be maintained. This assumption bounds the current status of Salem Unit 1 steam generators with significant margin.

Tubesheet inspections with probes capable of detecting crack like flaws have been extensively performed by several utilities with SGs similar to Salem Unit 1 (fabricated with alloy 600 Thermally Treated (TT) tubing). These inspections included the Top of the Tubesheet (TTS) region, expansion anomalies within the tubesheet, and the tube end region near the weld. The industry inspections have demonstrated that flaws in the tubesheet are negligible when considering the number of tubes inspected, severity of degradation detected, and when compared to the conservative assumption of H* that all tubes are severed. As an example of industry inspection results, tube flaw indications within the tubesheet have been found at the hot leg tube ends and in bulges/overexpansions at Vogtle (Westinghouse Model F SGs). Approximately 18,274 tube ends have been recently inspected at Vogtle, of which twenty-seven flaw indications have been found in the inspections within 1 inch of the tube end. All of these indications were small and none met the tube repair criteria in their current technical specifications.

PSEG has also performed inspections with probes capable of detecting crack like flaws within the tubesheet. These inspections included the TTS region and expansion anomalies within the tubesheet, and have not resulted in any flaws being detected. However, since the last scheduled SG inspection implemented Reference 2, this precluded any requirement to inspect the tube end region near the weld. Salem Unit 1 replacement SGs have only been operating since 1998, and therefore have accumulated much less operating time (EFPY) as compared to other utilities SGs. Furthermore, Salem Unit 1 SGs have been operated at reactor coolant temperatures less than, or equivalent to, those utilities SGs with extensive tube end inspection data. Consequently, based on plant operating history and parameters, the potential for SG tube end flaws at Salem Unit 1 is deemed to be less than that observed by other utilities.

Based on overall industry inspections, a limited number of flaws exist in the tube sheets of steam generators. The flaws that have been found are associated with residual stress conditions at either the tube ends or bulges/overexpansions within the tubesheet. No indications of a 360 degree sever has been detected in any steam generator. Consequently, the level of degradation in the steam generators is very limited compared to the assumption of "all tubes severed" that was utilized in the development of the H*. Therefore, structural integrity will be assured for the operating period between inspections allowed by TS 6.8.4.i, "Steam Generator (SG) Program".

From a leakage perspective, projections of accident induced steam generator tube leakage are based on leakage rate factors applied to leakage detected during normal operation. The multiplication factor used for Salem Unit 1 bounds the expected increased leakage in the event of an accident. The projected accident induced leakage remains the same for both the temporary one-time and permanent H* amendments. No primary-to-secondary steam generator tube leakage has been detected during the current operating cycle at Salem Unit 1.

Salem Unit 1 has not detected any crack like flaws anywhere in the SGs. In addition, the number of SG tubes identified with flaws from industry experience within the tubesheet is small in comparison to the input assumptions used in the development of the permanent H*. Consequently, significant margin exists between the current state of the Salem Unit 1 steam generators and the conservative assumptions used as the basis for the permanent H*. Structural and leakage integrity will continue to be assured for the operating period between inspections allowed by TS 6.8.4.i, "Steam Generator (SG) Program" with the implementation of the proposed one-time H*.

WCAP-17071-P recommends the 95% probability/50% confidence H* value of 11.2 inches; however, PSEG has chosen to use an H* value of 13.1 inches for additional conservatism.

2.0 PROPOSED CHANGE

TS 6.8.4.i.c. is revised as follows:

c. Provisions for SG tube repair criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

   The following *alternate* repair criteria ~~are applicable only for Refueling Outage 18 and the subsequent operating cycle: In lieu~~ *shall be applied as an alternative to* ~~of~~ the 40% *depth based* ~~of the nominal wall thickness repair~~ criteria: ~~the portion of the tube within the tubesheet of the inspected SGs shall be plugged in accordance with the following alternate repair criteria: Tubes with flaws located below 17 inches from the top of the tubesheet may remain in service regardless of size. Tubes with flaws identified in the portion of the tube from the top of the tubesheet to 17 inches below the top of the tubesheet shall be plugged on detection.~~

   For Refuel Outage 1R20 through the subsequent operating cycles until the next scheduled SG tube inspection, tubes with service-induced flaws located greater than 13.1 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 13.1 inches below the top of the tubesheet shall be plugged upon detection.

TS 6.8.4.i.d is revised as follows:

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. *For Refuel Outage 1R20 through the subsequent operating cycles until the next scheduled SG tube*

inspection, portions of the tube below 13.1 inches from the top of the tubesheet are excluded from this requirement.

~~In lieu of the above, the following inspection criteria are applicable only for Refueling Outage 18 and the subsequent operating cycle:~~
~~The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube beginning 17 inches below the top of the tubesheet on the tube hot leg side to 17 inches below the top of the tubesheet on the tube cold leg side.~~

The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

<u>TS 6.8.4.i.d.3 is revised as follows</u>:

3. If crack indications are found in ~~any~~ portions of the SG tube, *not excluded above*, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

<u>TS 6.9.1.10 is revised to include three additional reporting requirements</u>:

A report shall be submitted within 180 days after the initial entry into HOT SHUTDOWN following completion of an inspection performed in accordance with the Specification 6.8.4.i, "Steam Generator (SG) Program." The report shall include:

a. The scope of inspections performed on each SG,

b. Active degradation mechanisms found,

c. Nondestructive examination techniques utilized for each degradation mechanism,

d. Location, orientation (if linear), and measured sizes (if available) of service induced indications,

e. Number of tubes plugged during the inspection outage for each active degradation mechanism,

f. Total number and percentage of tubes plugged to date, and

g. The results of condition monitoring, including the results of tube pulls and in-situ testing.

~~h. The following reporting requirements are applicable only for refueling Outage 18 and the subsequent operating cycle:~~
~~The number of indications detected in the upper 17 inches of the tubesheet thickness along with their location, measured size, orientation, and whether the indication initiated on the primary or secondary side.~~

~~i. The following reporting requirement is applicable only for Refueling Outage 18 and the subsequent operating cycle:~~
~~The operational primary to secondary leakage rate observed in each steam generator during the cycle preceding the inspection and the calculated accident leakage rate for each steam generator from the lowermost 4 inches of tubing (the tubesheet is nominally 21.03 inches thick) for the most limiting accident. If the calculated leak rate is less than 2 times the total observed operational leakage rate, the 180 day report should describe how the calculated leak rate is determined.~~

Reporting requirements h, i and j are applicable for Refuel Outage 1R20 through the subsequent operating cycles until the next scheduled SG tube inspection.

h. The primary to secondary leakage rate observed in each SG (if it is not practical to assign the leakage to an individual SG, the entire primary to secondary leakage should be conservatively assumed to be from one SG) during the cycle proceeding the inspection which is the subject of the report,

i. The calculated accident induced leakage rate from the portion of the tubes below 13.1 inches from the top of the tubesheet for the most limiting accident in the most limiting SG. In addition, if the calculated accident induced leakage rate from the most limiting accident is less than 2.16 times the maximum operational primary to secondary leakage rate, the report should describe how it was determined,

j. The results of monitoring for tube axial displacement (slippage). If slippage is discovered, the implications of the discovery and corrective action shall be provided.

3.0 BACKGROUND

Salem Generating Station Unit 1 is a four loop Westinghouse designed plant with Model F steam generators having 5626 tubes in each SG (for a total of 22504 tubes). A total of 224 tubes are currently plugged in all four SG. The design of the SG includes Alloy 600 thermally treated tubing, full depth hydraulically expanded tubesheet joints, and stainless steel tube support plates with broached hole quatrefoils.

The steam generator inspection scope is governed by TS 6.8.4.i, Steam Generator (SG) Program; Nuclear Energy Institute (NEI) 97-06, Steam Generator Program Guidelines [Reference 3]; EPRI 1003138, Pressurized Water Reactor Steam Generator Examination Guidelines [Reference 4]; EPRI 1012987, Steam Generator Integrity Assessment Guidelines [Reference 5]; PSEG SG Program procedures ER-AP-420, "Steam Generator Management Program Activities", and ER-AP-420-0051, "Conduct of Steam Generator Management Program Activities"; and the results of the degradation assessments required by the SG Program. Criterion IX, "Control of Special Processes" of 10 CFR Part 50, Appendix B, requires in part that nondestructive testing be accomplished by qualified personnel using qualified procedures in accordance with the applicable criteria. The inspection techniques and equipment are capable of reliably detecting the known and potential specific degradation mechanisms applicable to Salem Unit 1. The inspection techniques, essential variables and equipment are qualified to Appendix H, "Performance Demonstration for Eddy Current Examination" of Reference 4.

Catawba Nuclear Station, Unit 2, (Catawba) reported indication of cracking following nondestructive eddy current examination of the SG tubes during their Fall 2004 outage. NRC Information Notice (IN) 2005-09, "Indications in Thermally Treated Alloy 600 Steam Generator Tubes and Tube-to-Tubesheet Welds" [Reference 6], provided industry notification of the Catawba issue. IN 2005-09 noted that Catawba reported crack like indications in the tubes approximately seven inches below the top of the hot leg tubesheet in one tube, and just above the tube-to-tubesheet welds in a region of the tube known as the tack expansion in several other tubes. Indications were also reported in the tube-end welds, also known as tube-to-tubesheet welds, which join the tube to the tubesheet.

PSEG policies and programs require the use of applicable industry operating experience in the operation and maintenance of Salem Unit 1 Station. The recent experience at Catawba, as noted in IN 2005-09, shows the importance of monitoring all tube locations (such as bulges, dents, dings, and other anomalies from the manufacture of the steam generators) with techniques capable of finding potential forms of degradation that may be occurring at these locations (as discussed in Generic Letter 2004-01, "Requirements for Steam Generator Tube Inspections"). Since the Salem Unit 1 Westinghouse Model F steam generators were fabricated with Alloy 600 thermally treated tubes similar to the Catawba Unit 2 Westinghouse Model D5 steam generators, a potential exists for Salem Unit 1 to identify tube indications similar to those reported at Catawba within the hot leg tubesheet region if similar inspections are performed during the Spring 2010 refueling outage.

Potential inspection plans for the tubes and tube welds underwent intensive industry discussions in March 2005. The findings in the Catawba SG tubes present two distinct issues with regard to the SG tubes at Salem Unit 1:

1) Indications in internal bulges and overexpansions within the hot leg tubesheet.

2) Indications at the elevation of the tack expansion transition.

Prior to each SG tube inspection, a degradation assessment, which includes a review of operating experience, is performed to identify degradation mechanisms that have a potential to be present in the Salem Unit 1 SGs. A validation assessment is also performed to verify that the eddy current techniques utilized are capable of detecting those flaw types that are identified in the degradation assessment. Based on the Catawba operating experience, PSEG revised the Salem Unit 1 TS consistent with Reference 2, and the SG inspection plan for the Spring 2007 refueling outage (1R18) included sampling of bulges and over expansions within the tubesheet region on the hot leg side. The sample was based on the guidance contained in EPRI 1003138, "Pressurized Water Reactor Steam Generator Examination Guidelines," Revision 6, and TS 6.8.4.i, Steam Generator (SG) Program. According to EPRI SG examination guidelines, the inspection plan is expanded if necessary due to confirmed degradation in the region required to be examined (i.e. a tube crack). However, degradation was not detected in the tubesheet region in 1R18.

As a result of these potential issues and the possibility of unnecessarily plugging tubes in the Salem Unit 1 SGs, PSEG is proposing changes to TS 6.8.4.i to limit the steam generator tube inspection and repair (plugging) to the portion of tubing from 13.1 inches below the top of the tubesheet.

4.0 TECHNICAL EVALUATION

To preclude unnecessarily plugging tubes in the Salem Unit 1 SGs, tube inspections will be limited to identifying and plugging degradation in the portion of the tube within the tubesheet necessary to maintain structural and leakage integrity in both normal and accident conditions. The technical evaluation for the inspection and repair methodology is provided in Westinghouse Electric Company, LLC WCAP-17071-P, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model F)"[4]. The evaluation is based on the use of finite element model structural analysis and a bounding leak rate evaluation based on contact pressure between the tube and the tubesheet during normal and postulated accident conditions. The limited tubesheet inspection criteria were developed for the tubesheet region of the Salem Unit 1 Model F SG considering the most stringent loads associated with plant operation, including transients and postulated accident conditions. The limited tubesheet inspection criteria were selected to prevent tube pull out from the tubesheet due to due to axial end cap loads acting on the tube and to ensure that the accident induced leakage limits are not exceeded. WCAP-17071-P provides technical justification for limiting the inspection in the tubesheet expansion region to less than the full depth of the tubesheet.

The basis for determining the portion of the tube which requires eddy current inspection within the tubesheet is based upon evaluation and testing programs that quantified the tube-to-tubesheet radial contact pressure for bounding plant

[4] Reference to WCAP -17071 throughout this submittal includes not only the originally issued WCAP but also all changes to the WCAP documented by the response to the Reference 9 and 10 RAIs (Attachments 7, 10 and 11).

conditions as described in WCAP-17071-P. The tube-to-tubesheet radial contact pressure provides resistance to tube pull out.

Primary-to-secondary leakage from tube degradation is assumed to occur in several design basis accidents: main steam line break (SLB), locked rotor[5], and control rod ejection. The radiological dose consequences associated with this assumed leakage are evaluated to ensure that they remain within regulatory limits (e.g., 10 CFR 50.67, GDC 19). The accident induced leakage performance criteria are intended to ensure the primary-to-secondary leak rate during any accident does not exceed the primary-to-secondary leak rate assumed in the accident analysis. Radiological dose consequences define the limiting accident condition for the H* justification.

The constraint that is provided by the tubesheet precludes tube burst for cracks within the tubesheet. The criteria for tube burst described in NEI 97-06 and NRC Regulatory Guide (RG) 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes," [Reference 7] are satisfied due to the constraint provided by the tubesheet. Through application of the limited tubesheet inspection scope as described below, the existing operating leakage limit provides assurance that excessive leakage (i.e., greater than accident analysis assumptions) will not occur. The accident analysis calculations have an assumption of 0.6 gpm at room temperature (gpmRT) primary-to-secondary leakage in a single SG and 1 gpm at room temperature (gpmRT) total primary-to-secondary leakage for all SGs. This apportioned primary-to-secondary leakage is used in the Main Steam Line Break and Locked Rotor accidents. Primary-to-secondary leakage of 1 gpm at room temperature (gpmRT) in a single SG is used in the Control Rod Ejection (CRE) accident. The TS operational leak rate limit is 150 gallons per day (gpd) (0.104 gpmRT). The maximum accident leak rate ratio for Salem Unit 1 is 2.16 (Table 9-7, Reference 1, as revised by the response to RAI 24 (Attachment 7)). Consequently, this results in significant margin between the conservatively estimated accident leakage and the allowable accident leakage.

Plant-specific operating conditions are used to generate the overall leakage factor ratios that are used in the condition monitoring and operational assessments. The plant-specific data provide the initial conditions for application of the transient input data. The results of the analysis of the plant-specific inputs to determine the bounding plant for each model of SG and to assure that the design basis accident contact pressures are greater than the normal operating pressure contact pressure are contained in Section 6 of WCAP-17071-P.

The leak rate ratio (accident induced leak rate to operational leak rate) is directly proportional to the change in differential pressure and inversely proportional to the dynamic viscosity. Since dynamic viscosity decreases with an increase in temperature, an increase in temperature results in an increase in leak rate. However, for both the postulated SLB and Feed Line Break (FLB) events, a plant cool down event would occur and the subsequent temperatures in the reactor

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[5] Note that, contrary to WCAP-17071 Section 9.2.2, Salem Unit 1 licensing basis does not include the reactor coolant pump locked rotor with a stuck open power operated relief valve (PORV) transient. This does not alter any of the conclusions of the WCAP. See Attachment 16.

coolant system (RCS) would not be expected to exceed the temperatures at plant no load conditions. Thus, an increase in leakage would not be expected to occur as a result of the temperature change. The increase in leakage would only be a function of the increase in primary-to-secondary pressure differential. The resulting leak rate ratio for the SLB and FLB events is 2.16 (Table 9-7, Reference 1, as revised by the response to RAI 24 (Attachment 7)) for Salem Unit 1.

The other design basis accidents, such as the postulated locked rotor event and the control rod ejection event, are conservatively modeled using the design specification transients that result in increased temperatures in the SG hot and cold legs for a period of time. As previously noted, dynamic viscosity decreases with increasing temperature. Therefore, leakage would be expected to increase due to decreasing viscosity and increasing differential pressure for the duration of time that there is a rise in RCS temperature. For transients other than a SLB and FLB, the length of time that a plant with Model F SGs will exceed the normal operating differential pressure across the tubesheet is less than 30 seconds. As the accident induced leakage performance criteria is defined in gallons per minute, the leak rate for a locked rotor event can be integrated over a minute for comparison to the limit. Time integration permits an increase in acceptable leakage during the time of peak pressure differential by approximately a factor of two because of the short duration (less than 30 seconds) of the elevated pressure differential. This translates into an effective reduction in the leakage factor by the same factor of two for the locked rotor event. Therefore, for the locked rotor event, the leakage factor of 1.55 (Table 9-7, Reference 1, as revised by the response to RAI 24 (Attachment 7)) for Salem Unit 1 is adjusted downward to a factor of 0.78. Similarly, for the control rod ejection event, the duration of the elevated pressure differential is less than 10 seconds. Thus, the peak leakage factor is reduced by a factor of six, from 2.31 to 0.39. Due to the short duration of the transients above Normal Operating Pressure (NOP) differential, no leakage factor is required for the locked rotor and control rod ejection events (i.e., the leakage factor is under 1.0 for both transients).

The plant transient response following a full power double-ended main feedwater line rupture corresponding to "best estimate" initial conditions and operating characteristics, as generally presented in steam generator design transients and in the UFSAR Chapter 15.0 safety analysis, indicates that the transient for a Model F SG exhibits a cool down characteristic instead of a heat-up transient. The use of either the component design specification transient or the Chapter 15.0 safety transient for leakage analysis for FLB is overly conservative because:

- The assumptions on which the FLB design transient is based are specifically intended to establish a conservative structural (fatigue) design basis for RCS components; however, H* does not involve component structural and fatigue issues. The best estimate transient is considered more appropriate for use in the H* leakage calculations.

- For the Model F SG, the FLB transient curve (Figure 9-5, Reference 1) represents a double-ended rupture of the main feedwater line concurrent with both station blackout (loss of main feedwater and reactor coolant pump coast down) and turbine trip.

- The assumptions on which the FLB safety analysis is based are specifically intended to establish a conservative basis for minimum auxiliary feedwater (AFW) capacity and combines worst case assumptions, which are exceptionally more severe when the FLB occurs inside containment. For example, environmental errors that are applied to reactor trip and engineered safety features actuation would no longer be applicable. This would result in much earlier reactor trip and greatly increase the SG liquid mass available to provide cooling to the RCS.

A SLB event would have similarities to a FLB except that the break flow path would include the secondary separators, which could only result in an increased initial cooldown (because of retained liquid inventory available for cooling) when compared to the FLB transient. A SLB could not result in more limiting temperature conditions than a FLB.

In accordance with plant operating procedures, the operator would take action following a high energy secondary line break to stabilize the RCS conditions. The expectation for a SLB or FLB with credited operator action is to stop the system cooldown through isolation of the faulted steam generator and control of temperature by the AFW system. Steam pressure control would be established by either the steam generator safety valves or the atmospheric relief valves. For any of the steam pressure control operations, the maximum temperature would be approximately the no load temperature and would be well below normal operating temperature.

Since the best estimate FLB transient temperature would not be expected to exceed the normal operating temperature, the viscosity ratio for the FLB transient is set to 1.0.

The leakage factor of 2.16 for Salem Unit 1 for a postulated SLB/FLB has been calculated as shown in Table 9-7 of WCAP-17071-P, as revised by the response to RAI 24 (Attachment 7). Specifically, for the condition monitoring (CM) assessment, the component of leakage from the prior cycle from below the H* distance will be multiplied by a factor of 2.16 and added to the total leakage from any other source and compared to the allowable accident induced leakage limit. For the operational assessment (OA), the difference between the allowable leakage and the accident induced leakage from sources other than the tubesheet expansion region will be divided by 2.16 and compared to the observed operational leakage.

Reference 1 redefines the primary pressure boundary. The tube to tubesheet weld no longer functions as a portion of this boundary. The hydraulic expansion of the tube into the tubesheet over the H* distance now functions as the primary pressure boundary in the area of the tube and tubesheet, maintaining the structural and leakage integrity over the full range of steam generator operating conditions, including the most limiting accident conditions. The evaluation in Reference 1 determined that degradation in tubing below 11.2 inches from the top of the tubesheet does not require inspection or repair (plugging). The inspection of the portion of the tubes above 11.2 inches from the top of the tubesheet for tubes that have been hydraulically expanded in the tubesheet

provides a high level of confidence that the structural and leakage performance criteria are maintained during normal operating and accident conditions.

Reference 1 (Section 8.0) recommended a final value of H* of 11.2 inches below the top of the tubesheet for the entire bundle of tubes. However, PSEG has chosen to use a more conservative value of 13.1 inches. This more conservative value was discussed between the NRC staff and industry representatives on April 24, 2009 and May 1, 2009.

WCAP-17071-P, Section 9.8, provides a review of leak rate susceptibility to tube slippage and concluded that the tubes are fully restrained against motion under very conservative design and analysis assumptions such that tube slippage is not a credible event for any tube in the bundle. However, in response to a NRC staff request, PSEG has included monitoring for tube slippage as part of the steam generator tube inspection program.

In addition the NRC staff has requested that licensees determine if there are any significant deviations in the location of the bottom of the expansion transition (BET) relative to the top of tubesheet that would invalidate assumptions in WCAP-17071-P. Therefore, PSEG commits to perform a one-time verification of the tube expansion to locate any significant deviations in the distance from the top of the tubesheet to the BET. If any deviations are found, the condition will be entered into the corrective action program and dispositioned. Additionally, PSEG commits to notify the NRC of significant deviations.

5.0 REGULATORY EVALUTATION

5.1 Applicable Regulatory Requirements/Criteria

General Design Criteria (GDC) 1, 2, 4, 14, 30, 31, and 32 of 10 CFR 50, Appendix A, define requirements for the reactor coolant pressure boundary (RCPB) with respect to structural and leakage integrity.

GDC 19 of 10 CFR 50, Appendix A, defines requirements for the control room and for the radiation protection of the operators working within it. Accidents involving the leakage or burst of SG tubing comprise a challenge to the habitability of the control room.

10 CFR 50, Appendix B, establishes quality assurance requirements for the design, construction, and operation of safety related components. The pertinent requirements of this appendix apply to all activities affecting the safety related functions of these components. These requirements are described in Criteria IX, XI, and XVI of Appendix B and include control of special processes, inspection, testing, and corrective action.

10 CFR 50.67, Accident Source Term, establishes limits on the accident source term used in design basis radiological consequence analyses with regard to radiation exposure to members of the public and to control room occupants.

Under 10 CFR 50.65, the Maintenance Rule, licensees classify SGs as risk significant components because they are relied upon to remain functional during and after design basis events. SGs are to be monitored under 10 CFR 50.65(a) (2) against industry established performance criteria. Meeting the performance criteria of NEI 97-06, Revision 2, provides reasonable assurance that the SG tubing remains capable of fulfilling its specific safety function of maintaining the reactor coolant pressure boundary. The NEI 97-06, Revision 2, SG performance criteria are:

- All in-service SG tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, cool down, and all anticipated transients included in the design specification) and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design and licensing basis shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial loads.

- The primary-to-secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 1 gpm per SG, except for specific types of degradation at specific locations when implementing alternate repair criteria as documented in the Steam Generator Program technical specifications.

- The RCS operational primary-to-secondary leakage through any one SG shall be limited to 150 gallons per day.

The proposed change defines the portion of the tube that is engaged in the tubesheet from the secondary face that is required to maintain structural and leakage integrity over the full range of SG operating conditions, including the most limiting accident conditions. The evaluation in WCAP-17071-P[6] determined that degradation in tubing below 11.2 inches from the top of the tubesheet portion of the tube does not require plugging and serves as the bases for the SG tube inspection program. PSEG has chosen to use an H* value of 13.1 inches for additional

[6] Reference to WCAP -17071 throughout this submittal includes not only the originally issued WCAP but also all changes to the WCAP documented by the response to the Reference 9 and 10 RAIs (Attachments 7, 10 and 11).

conservatism. As such, the Salem Unit 1 inspection program provides a high level of confidence that the structural and leakage criteria are maintained during normal operating and accident conditions.

5.2 No Significant Hazards Consideration

This amendment application proposes to revise Technical Specification (TS) 6.8.4.i, "Steam Generator (SG) Program," to exclude portions of the tubes within the tubesheet from periodic steam generator inspections. In addition, this amendment proposes to revise Technical Specification (TS) 6.9.1.10, "Steam Generator Tube Inspection Report" to provide reporting requirements specific to the alternate repair criteria. Application of the structural analysis and leak rate evaluation results, to exclude portions of the tubes from inspection and repair, is interpreted to constitute a redefinition of the primary-to-secondary pressure boundary.

The proposed change defines the safety significant portion of the tube that must be inspected and repaired. A justification has been developed by Westinghouse Electric Company, LLC to identify the specific inspection depth below which any type of degradation can be shown to have no impact on Nuclear Energy Institute (NEI) 97-06 (Reference 3), "Steam Generator Program Guidelines," performance criteria.

PSEG has evaluated whether or not a significant hazards consideration is involved with the proposed amendment by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

1. *The proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.*

   The previously analyzed accidents are initiated by the failure of plant structures, systems, or components. The proposed change that alters the steam generator (SG) inspection and reporting criteria does not have a detrimental impact on the integrity of any plant structure, system, or component that initiates an analyzed event. The proposed change will not alter the operation of, or otherwise increase the failure probability of any plant equipment that initiates an analyzed accident.

   Of the applicable accidents previously evaluated, the limiting transients with consideration to the proposed change to the SG tube inspection and repair criteria are the steam generator tube rupture (SGTR) event, the steam line break (SLB), and the feed line break (FLB) postulated accidents.

   During the SGTR event, the required structural integrity margins of the SG tubes and the tube-to-tubesheet joint over the H* distance will be maintained. Tube rupture in tubes with cracks within the tubesheet is precluded by the constraint provided by the presence of the tubesheet and the tube-to-tubesheet joint. Tube burst cannot occur within the thickness of the tubesheet. The tube-to-tubesheet joint constraint

results from the hydraulic expansion process, thermal expansion mismatch between the tube and tubesheet, and from the differential pressure between the primary and secondary side, and tubesheet rotation. Based on this design, the structural margins against burst, as discussed in Regulatory Guide (RG) 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes," and Technical Specification 6.8.4.i, are maintained for both normal and postulated accident conditions.

The proposed change has no impact on the structural or leakage integrity of the portion of the tube outside of the tubesheet. The proposed change maintains structural and leakage integrity of the SG tubes consistent with the performance criteria of Technical Specification 6.8.4.i. Therefore, the proposed change results in no significant increase in the probability of the occurrence of a SGTR accident.

At normal operating pressures, leakage from tube degradation below the proposed limited inspection depth is limited by the tube-to-tubesheet crevice. Consequently, negligible normal operating leakage is expected from degradation below the inspected depth within the tubesheet region. The consequences of an SGTR event are not affected by the primary-to-secondary leakage flow during the event as primary-to-secondary leakage flow through a postulated tube that has been pulled out of the tubesheet is essentially equivalent to a severed tube. Therefore, the proposed change does not result in a significant increase in the consequences of a SGTR

The probability of a SLB is unaffected by the potential failure of a steam generator tube as the failure of tube is not an initiator for a SLB event.

The leakage factor of 2.16 for Salem Unit 1, for a postulated SLB/FLB, has been calculated as shown in Table 9-7 of WCAP-17071-P as revised by the response to RAI 24 (Attachment 7). Through application of the limited tubesheet inspection scope, the existing operating leakage limit provides assurance that excessive leakage (i.e., greater than accident analysis assumptions) will not occur. The accident analysis calculations have an assumption of 0.6 gpm at room temperature (gpmRT) primary-to-secondary leakage in a single SG and 1 gpm at room temperature (gpmRT) total primary-to-secondary leakage for all SGs. This apportioned primary-to-secondary leakage is used in the Main Steam Line Break and Locked Rotor accidents. Primary-to-secondary leakage of 1 gpm at room temperature (gpmRT) in a single SG is used in the Control Rod Ejection (CRE) accident.

No leakage factor will be applied to the locked rotor or control rod ejection transients due to their short duration.

The TS operational leak rate limit is 150 gallons per day (gpd) (0.104 gpmRT). The maximum accident leak rate ratio for Salem Unit 1 is

2.16. Consequently, this results in significant margin between the conservatively estimated accident leakage and the allowable accident leakage.

For the condition monitoring (CM) assessment, the component of leakage from the prior cycle from below the H* distance will be multiplied by a factor of 2.16 and added to the total leakage from any other source and compared to the allowable accident induced leakage limit. For the operational assessment (OA), the difference in the leakage between the allowable leakage and the accident induced leakage from sources other than the tubesheet expansion region will be divided by 2.16 and compared to the observed operational leakage.

Based on the above, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. *The proposed changes do not create the possibility of a new or different kind of accident from any previously evaluated.*

   The proposed change that alters the steam generator inspection and reporting criteria does not introduce any new equipment, create new failure modes for existing equipment, or create any new limiting single failures. Plant operation will not be altered, and all safety functions will continue to perform as previously assumed in accident analyses. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any previously evaluated.

3. *The proposed changes do not involve a significant reduction in the margin of safety.*

   The proposed change defines the safety significant portion of the tube that must be inspected and repaired (plugged). WCAP-17071-P identifies the specific inspection depth below which any type tube degradation shown to have no impact on the performance criteria in NEI 97-06 Rev. 2, "Steam Generator Program Guidelines."

   The proposed change that alters the steam generator inspection and reporting criteria maintains the required structural margins of the SG tubes for both normal and accident conditions. Nuclear Energy Institute 97-06, "Steam Generator Program Guidelines," and NRC Regulatory Guide (RG) 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes," are used as the bases in the development of the limited hot leg tubesheet inspection depth methodology for determining that SG tube integrity considerations are maintained within acceptable limits. RG 1.121 describes a method acceptable to the NRC for meeting General Design Criteria (GDC) 14, "Reactor Coolant Pressure Boundary," GDC 15, "Reactor Coolant System Design," GDC 31, "Fracture Prevention of Reactor Coolant Pressure Boundary," and GDC 32, "Inspection of Reactor Coolant Pressure

Boundary," by reducing the probability and consequences of a SGTR. RG 1.121 concludes that by determining the limiting safe conditions for tube wall degradation, the probability and consequences of a SGTR are reduced. This RG uses safety factors on loads for tube burst that are consistent with the requirements of Section III of the American Society of Mechanical Engineers (ASME) Code.

For axially oriented cracking located within the tubesheet, tube burst is precluded due to the presence of the tubesheet. For circumferentially oriented cracking, Westinghouse WCAP-17071-P defines a length of degradation-free expanded tubing that provides the necessary resistance to tube pullout due to the pressure induced forces, with applicable safety factors applied. Application of the limited hot and cold leg tubesheet inspection criteria will preclude unacceptable primary-to-secondary leakage during all plant conditions. The methodology for determining leakage as described in WCAP-17072-P shows that significant margin exists between an acceptable level of leakage during normal operating conditions that ensures meeting the accident-induced leakage assumptions and the TS leakage limit of 150 gpd.

Based on the above it is concluded that the proposed changes do not result in any reduction in a margin of safety.

5.3 Conclusion

The safety significant portion of the tube is the length of the tube that is engaged within the tubesheet to the top of the tubesheet secondary face that is required to maintain structural and leakage integrity over the full range of SG operating conditions, including the most limiting accident conditions. WCAP- 17072-P determined that the degradation in tubing below the safety significant portion of the tube does not require inspection, plugging, or repair. WCAP-17072-P serves as the basis for the tubesheet inspection criteria known as the H* criteria, which is intended to ensure the primary to secondary leak rate during any accident does not exceed the leak rate assumed in the accident analysis. Based on the considerations above, PSEG concludes that the proposed amendment presents no significant hazards consideration under the standards set forth in 10 CFR 50.92(c) and, accordingly, a finding of "no significant hazards consideration" is justified.

In conclusion, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

6.0 ENVIRONMENTAL CONSIDERATIONS

PSEG has evaluated the proposed amendment for environmental considerations. The review has determined that the proposed amendment would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, and would change an inspection or surveillance requirement. However, the proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendments meet the eligibility criterion for categorical exclusion set for in 10 CFR 51.22(c) (9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment needs to be prepared in connection with the proposed amendment.

7.0 REFERENCES

1. Westinghouse Electric Company WCAP-17071-P," H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model F)" April, 2009

2. Letter from NRC to PSEG: "Salem Nuclear Generating Station, Unit 1, Issuance of Amendment Re: Steam Generator Alternate Repair Criteria (TAC No. MD4034)", dated March 27, 2007

3. NEI 97-06, "Steam Generator Program Guidelines" Revision 2, May 2005

4. EPRI 1003138, "Pressurized Water Reactor Steam Generator Examination Guidelines," Revision 6 (Note the EPRI document number changes with each revision. Revision 7 of the Guidelines is EPRI 1013796. Revision 6 was in effect during the most recent inspection at Salem Unit 1)

5. EPRI 1012987, Steam Generator Integrity Assessment Guidelines

6. NRC Information Notice 2005-09, "Indications in Thermally Treated Alloy 600 Steam Generator Tubes and Tube-to-Tubesheet Welds," April 7, 2005

7. NRC Regulatory Guide 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes," August 1976

8. (1) Letter from NRC to Southern Nuclear Operating Company, Inc., "Vogtle Electric Generating Plant, Units 1 and 2, Issuance of Amendments Regarding Technical Specification (TS) Section 5.5.9, "Steam Generator Program," for Interim Alternate Repair Criteria (TAC NOS. ME1339 and ME 1340)," dated September 24, 2009

9. (2) Letter from D. Wright, USNRC, to M. J. Ajluni, Southern Nuclear Operating Company, Inc., "Vogtle Electric Generating Plant, Units 1 and 2, Request for Additional Information Regarding Steam Generator Program (TAC NOS. ME1339 and ME1340)", dated July 10, 2009

10. (3) Letter from D. Wright, USNRC, to M. J. Ajluni, Southern Nuclear Operating Company, Inc., "Vogtle Electric Generating Plant, Units 1 and 2, Request for Additional Information Regarding Steam Generator Program (TAC NOS. ME1339 and ME1340)", dated August 5, 2009

Mark-up of Proposed Technical Specification Pages

The following Technical Specifications pages for **Facility Operating License DPR-70** are affected by this change request:

Technical Specification	Page
6.8.4.i	6-19c, 19d
6.9.1.10	6-24b

outage during which the SG tubes are inspected or plugged to confirm that the performance criteria are being met.

b. Performance criteria for SG tube integrity. SG tube integrity shall be maintained by meeting the performance criteria for tube structural integrity, accident induced leakage, and operational leakage.

1. Structural integrity performance criterion: All in-service steam generator tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cool down and all anticipated transients included in the design specification) and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.

2. Accident induced leakage performance criterion: The primary-to-secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 1 gallon per minute per SG.

3. The operational leakage performance criterion is specified in LCO 3.4.6.2, "Reactor Coolant System Operational Leakage."

c. Provisions for SG tube repair criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

The following *alternate* repair criteria ~~are applicable only for Refueling Outage 18 and the subsequent operating cycle: In lieu~~ *shall be applied as an alternative to* ~~of~~ the 40% *depth based* ~~of the nominal wall thickness repair~~ criteria:, ~~the portion of the tube within the tubesheet of the inspected SGs shall be plugged in accordance with the following alternate repair criteria: Tubes with flaws located below 17 inches from the top of the tubesheet may remain in service regardless of size. Tubes with flaws identified in the portion of the tube from the top of the tubesheet to 17 inches below the top of the tubesheet shall be plugged on detection.~~

For Refuel Outage 1R20 through the subsequent operating cycles until the next scheduled SG tube inspection, tubes with service-induced flaws located greater than 13.1 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 13.1 inches below the top of the tubesheet shall be plugged upon detection.

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the

tube outlet, and that may satisfy the applicable tube repair criteria. *For Refuel Outage 1R20 through the subsequent operating cycles until the next scheduled SG tube inspection, portions of the tube below 13.1 inches from the top of the tubesheet are excluded from this requirement.*

~~In lieu of the above, the following inspection criteria are applicable only for Refueling Outage 18 and the subsequent operating cycle:~~
~~The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube beginning 17 inches below the top of the tubesheet on the tube hot leg side to 17 inches below the top of the tubesheet on the tube cold leg side.~~

The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG replacement.

2. Inspect 100% of the tubes at sequential periods of 120, 90, and thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No SG shall operate for more than 48 effective full power months or two refueling outages (whichever is less) without being inspected.

3. If crack indications are found in ~~any~~ portions of the SG tube *not excluded above*, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

e. Provisions for monitoring operational primary-to-secondary leakage.

~~h. The following reporting requirements are applicable only for refueling Outage 18 and the subsequent operating cycle:~~
~~The number of indications detected in the upper 17 inches of the tubesheet thickness along with their location, measured size, orientation, and whether the indication initiated on the primary or secondary side.~~

~~i. The following reporting requirement is applicable only for Refueling Outage 18 and the subsequent operating cycle:~~
~~The operational primary to secondary leakage rate observed in each steam generator during the cycle preceding the inspection and the calculated accident leakage rate for each steam generator from the lowermost 4 inches of tubing (the tubesheet is nominally 21.03 inches thick) for the most limiting accident. If the calculated leak rate is less than 2 times the total observed operational leakage rate, the 180 day report should describe how the calculated leak rate is determined.~~

Reporting requirements h, i and j are applicable for Refuel Outage 1R20 through the subsequent operating cycles until the next scheduled SG tube inspection

h. The primary to secondary leakage rate observed in each SG (if it is not practical to assign the leakage to an individual SG, the entire primary to secondary leakage should be conservatively assumed to be from one SG) during the cycle proceeding the inspection which is the subject of the report,

i. The calculated accident induced leakage rate from the portion of the tubes below 13.1 inches from the top of the tubesheet for the most limiting accident in the most limiting SG. In addition, if the calculated accident induced leakage rate from the most limiting accident is less than 2.16 times the maximum operational primary to secondary leakage rate, the report should describe how it was determined,

j. The results of monitoring for tube axial displacement (slippage). If slippage is discovered, the implications of the discovery and corrective action shall be provided.

SPECIAL REPORTS

6.9.2 Special reports shall be submitted to the U.S. Nuclear Regulatory Commission, Document Control Desk, Washington, D.C. 20555, with a copy to the Administrator, USNRC Region I within the time period specified for each report.

6.9.3 Violations of the requirements of the fire protection program described in the Updated Final Safety Analysis Report which would have adversely affected the ability to achieve and maintain safe shutdown in the event of a fire shall be submitted to the U. S. Nuclear Regulatory Commission, Document Control Desk, Washington, DC 20555, with a copy to the Regional Administrator of the Regional Office of the NRC via the Licensee Event Report System within 30 days.

6.9.4 When a report is required by ACTION 8 or 9 of Table 3.3-11 "Accident Monitoring Instrumentation", a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring for inadequate core cooling, the cause of the inoperability, and the plans and schedule for restoring the instrument channels to OPERABLE status.

Mark-up of Proposed Technical Specification Bases Pages
(Information Only)

3/4.4.4 PRESSURIZER

The limit on the maximum water volume in the pressurizer assures that the parameter is maintained within the normal steady-state envelope of operation assumed in the SAR. The limit is consistent with the initial SAR assumptions. The 12 hour periodic surveillance is sufficient to assure that the parameter is restored to within its limit following expected transient operation. The maximum water volume also ensures that a steam bubble is formed and thus the RCS is not a hydraulically solid system. The requirement that a minimum number of pressurizer heaters be OPERABLE assures that the plant will be able to establish natural circulation.

3/4.4.5 STEAM GENERATOR (SG) TUBE INTEGRITY

The LCO requires that SG tube integrity be maintained. The LCO also requires that all SG tubes that satisfy the repair criteria be plugged in accordance with the Steam Generator Program.

During an SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is removed from service by plugging. If a tube was determined to satisfy the repair criteria but was not plugged, the tube may still have tube integrity.

In the context of this Specification, a SG tube is defined as the entire length of the tube, including the tube wall between the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at the tube outlet. *For Refuel Outage 1R20 through the subsequent operating cycles until the next scheduled SG tube inspection, tubes with service-induced flaws located greater than 13.1 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 13.1 inches below the top of the tubesheet shall be plugged upon detection.* ~~For Refueling Outage 18 and the subsequent operating cycle only, the following definition applies: A SG tube is defined as the length of the tube beginning 17 inches from the top of the tubesheet on the tube hot leg side to 17 inches below the top of the tubesheet on the tube cold leg side as defined in LCR S07-01 (including WCAP-16640-P).~~ The tube-to-tubesheet weld is not considered part of the tube.

A SG tube has tube integrity when it satisfies the SG performance criteria. The SG performance criteria are defined in Specification 6.8.4.i, "Steam Generator (SG) Program," and describe acceptable SG tube performance. The Steam Generator Program also provides the evaluation process for determining conformance with the SG performance criteria.

There are three SG performance criteria: structural integrity, accident induced leakage, and operational leakage. Failure to meet any one of these criteria is considered failure to meet the LCO.

The structural integrity performance criterion provides a margin of safety against tube burst or collapse under normal and accident conditions, and ensures structural integrity of the SG tubes under all anticipated transients included in the design specification. Tube burst is defined as, "The gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation." Tube collapse is defined as, "For the load displacement curve for a given structure, collapse occurs at the top of the load versus displacement curve where the slope of the curve becomes zero." The structural integrity performance criterion provides guidance on assessing loads that significantly affect burst or collapse. In that context, the term "significant" is defined as, "An accident loading condition other than differential pressure is considered significant when the addition of such loads in the assessment of the structural integrity performance criterion could cause a lower structural limit or limiting burst/collapse condition to be established."