UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

March 29, 2010

Mr. Thomas Joyce
President and Chief Nuclear Officer
PSEG Nuclear
P.O. Box 236, N09
Hancocks Bridge, NJ 08038

SUBJECT: SALEM NUCLEAR GENERATING STATION, UNIT NO. 1, ISSUANCE OF AMENDMENT RE: STEAM GENERATOR INSPECTION SCOPE AND REPAIR REQUIREMENTS (TAC NO. ME2374)

Dear Mr. Joyce:

The Commission has issued the enclosed Amendment No. 294 to Facility Operating License No. DPR-70 for the Salem Nuclear Generating Station, Unit No. 1. This amendment consists of changes to the Technical Specifications (TSs) in response to your application dated October 8, 2009, as supplemented by letter dated February 25, 2010.

The amendment approves a one-time change to TS 6.8.4.i, "Steam Generator (SG) Program," regarding the SG tube inspection and repair required for the portion of the SG tubes passing through the tubesheet region. Specifically, for Salem Unit No. 1 refueling outage 20 (planned for spring 2010) and subsequent operating cycles until the next scheduled SG tube inspection, the amendment limits the required inspection (and repair if degradation is found) to the portions of the SG tubes passing through the upper 13.1 inches of the approximate 21-inch tubesheet region. In addition, the amendment revises TS 6.9.1.10, "Steam Generator Tube Inspection Report," to provide reporting requirements specific to the one-time change.

A copy of our safety evaluation is also enclosed. Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

Richard B. Ennis, Senior Project Manager
Plant Licensing Branch I-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-272

Enclosures:
1. Amendment No. 294 to License No. DPR-70
2. Safety Evaluation

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

PSEG NUCLEAR, LLC

EXELON GENERATION COMPANY, LLC

DOCKET NO. 50-272

SALEM NUCLEAR GENERATING STATION, UNIT NO. 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 294
License No. DPR-70

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment filed by PSEG Nuclear LLC, acting on behalf of itself and Exelon Generation Company, LLC (the licensees) dated October 8, 2009, as supplemented by letter dated February 25, 2010, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in Title 10 of the *Code of Federal Regulations* (10 CFR), Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance: (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations set forth in 10 CFR Chapter I;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Facility Operating License No. DPR-70 is hereby amended to read as follows:

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 294, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of its date of issuance and shall be implemented prior to completion of refueling outage 20 (currently scheduled for spring 2010).

FOR THE NUCLEAR REGULATORY COMMISSION

Harold K. Chernoff, Chief
Plant Licensing Branch I-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Facility Operating License and the Technical Specifications

Date of Issuance: March 29, 2010

ATTACHMENT TO LICENSE AMENDMENT NO. 294

FACILITY OPERATING LICENSE NO. DPR-70

DOCKET NO. 50-272

Replace the following page of Facility Operating License No. DPR-70 with the attached revised page as indicated. The revised page is identified by amendment number and contains marginal lines indicating the areas of change.

Remove	Insert
Page 4	Page 4

Replace the following pages of the Appendix A, Technical Specifications, with the attached revised pages as indicated. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove	Insert
6-19c	6-19c
6-19d	6-19d
6-24b	6-24b

(1) Maximum Power Level

PSEG Nuclear LLC is authorized to operate the facility at a steady state reactor core power level not in excess of 3459 megawatts (one hundred percent of rated core power).

(2) Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 294, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

(3) Deleted Per Amendment 22, 11-20-79

(4) Less than Four Loop Operation

PSEG Nuclear LLC shall not operate the reactor at power levels above P-7 (as defined in Table 3.3-1 of Specification 3.3.1.1 of Appendix A to this license) with less than four (4) reactor coolant loops in operation until safety analyses for less than four loop operation have been submitted by the licensees and approval for less than four loop operation at power levels above P-7 has been granted by the Commission by Amendment of this license.

(5) PSEG Nuclear LLC shall implement and maintain in effect all provisions of the approved fire protection program as described in the Updated Final Safety Analysis Report, and as approved in the NRC Safety Evaluation Report dated November 20, 1979, and in its supplements, subject to the following provision:

> PSEG Nuclear LLC may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

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 shall be applied as an alternative to the 40% depth based criteria:

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.

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 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.

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 preceding 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 DELETED

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.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 294 TO FACILITY OPERATING LICENSE NO. DPR-70

PSEG NUCLEAR, LLC

EXELON GENERATION COMPANY, LLC

SALEM NUCLEAR GENERATING STATION, UNIT NO. 1

DOCKET NO. 50-272

1.0 INTRODUCTION

By letter dated October 8, 2009 (Reference 1), as supplemented by letter dated February 25, 2010 (Reference 20), PSEG Nuclear LLC (PSEG or the licensee) submitted a request for changes to the Salem Nuclear Generating Station (Salem), Unit No. 1, Technical Specifications (TSs). The request proposed changes to the inspection scope and repair requirements of TS 6.8.4.i, "Steam Generator (SG) Program" and to the reporting requirements of TS 6.9.1.10, "Steam Generator Tube Inspection Report." The proposed changes would be applicable to refueling outage 20 (1R20), planned for spring 2010, and the subsequent operating cycles until the next scheduled SG tube inspection. The proposed changes would establish alternate tube repair criteria, termed "H*" (and pronounced "H star") for portions of the SG tubes within the tubesheet.

The October 8, 2009, letter from PSEG includes a technical support document as an attachment (Reference 2). This technical support document is a generic document applicable to plants with Westinghouse Model F SGs, such as Salem Unit No. 1, and was intended to support permanent H* amendments for these plants. Prior to PSEG's October 8, 2009, submittal for Salem Unit No. 1, license amendment requests (LARs) for permanent H* amendments were submitted for several other plants with Model F SGs including, for example, Vogtle Unit Nos. 1 and 2 (Reference 3). The Nuclear Regulatory Commission (NRC or the Commission) staff reviewed these LARs and issued requests for additional information (RAIs) (see References 4 and 5 for Vogtle Unit Nos. 1 and 2). Anticipating that the same information would be requested for the Salem Unit No. 1 LAR, PSEG enclosed responses to these RAIs (References 6, 7 and 8) with its October 8, 2009, LAR submittal.

On September 2, 2009, in a teleconference between the NRC staff and industry personnel, NRC staff indicated that its concerns with eccentricity of the tubesheet tube bore in normal and accident conditions had not been completely resolved to their satisfaction (RAI question 1 in Reference 6 and RAI question 4 in Reference 8). The staff further indicated that there was insufficient time to resolve these issues to support approval of a 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 Salem Unit No. 1 refueling outage 20 through the subsequent operating cycles until the next scheduled SG tube inspection.

The supplement dated February 25, 2010, provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the NRC staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on January 5, 2010 (75 FR 464).

2.0 BACKGROUND

Salem Unit No. 1 has four Model F SGs that were designed and fabricated by Westinghouse. These are replacement SGs installed in 1997. There are 5,626 Alloy 600, thermally-treated tubes in each SG, each with an outside diameter of 0.688 inches and a nominal wall thickness of 0.040 inches. The tubes are hydraulically expanded for the full depth of the 21-inch tubesheet and are welded to the tubesheet at each tube end. Until the fall of 2004, no instances of stress corrosion cracking affecting the tubesheet region of thermally-treated Alloy 600 tubing had been reported at any nuclear power plants in the United States.

In the fall of 2004, crack-like indications were found in tubes in the tubesheet region of Catawba Nuclear Station Unit No. 2 (Catawba), which has Westinghouse Model D5 SGs. Like Salem Unit No. 1 the Catawba SGs use thermally-treated Alloy 600 tubing that is hydraulically expanded against the tubesheet. The crack-like indications at Catawba were found in a tube overexpansion (OXP), in the tack expansion region, and near the tube-to-tubesheet weld. An OXP is created when the tube is expanded into a tubesheet bore hole that is not perfectly round. These out-of-round conditions were created during the tubesheet drilling process by conditions such as drill bit wandering or chip gouging. The tack expansion is an approximately 1-inch long expansion at each tube end. The purpose of the tack expansion is to facilitate performing the tube-to-tubesheet weld, which is made prior to the hydraulic expansion of the tube over the full tubesheet depth.

Since the initial findings at Catawba in the fall of 2004, other nuclear plants have found crack-like indications in tubes within the tubesheet as well. These plants include Braidwood Unit No. 2, Byron Unit No. 2, Comanche Peak Unit No. 2, Surry Unit No. 2, Vogtle Unit No. 1, and Wolf Creek Unit No. 1. Most of the indications were found in the tack expansion region near the tube-end welds and were a mixture of axial and circumferential primary water stress corrosion cracking.

On October 2, 2006, PSEG submitted a LAR for H* alternate repair criteria for Salem Unit No. 1 (Reference 9). Similar LARs were submitted for other plants during the 2006 and 2007 period. These LARs were based on an analysis performed by Westinghouse that provided a technical basis for permanently limiting the scope of inspections, plugging, and repairs required for tubes within the tubesheet. The NRC staff was unable to complete its reviews of these LARs due to a number of unresolved technical issues, and by early 2008, these LARs had either been withdrawn or revised as interim amendments applicable to only one or two operating cycles, depending on the plant. By letter dated January 18, 2007, PSEG revised its LAR as an interim LAR applicable to refueling outage 18 (Spring 2007) and the subsequent operating interval. The interim LAR was approved by the NRC staff in Reference 10.

In a letter dated February 8, 2008 (Reference 11), the NRC staff identified the specific issues that needed to be addressed to support any future request for a permanent amendment, which included but were not limited to thermal expansion coefficients, crevice pressure assumptions, uncertainty models, acceptance standards for probabilistic assessment, and leakage resistance. As discussed in Section 1.0 of this safety evaluation, several licensees (other than PSEG) submitted LARs for a permanent H* amendment, beginning in May 2009, which were intended to address the issues identified by the NRC staff in Reference 11. However, new information contained in these submittals led to staff questions about tubesheet bore eccentricity that have not been addressed to the staff's satisfaction to date. As such, the staff determined that it could not approve those H* amendments on a permanent basis. Based on the relatively early stage of stress corrosion cracking in the tubesheet region of the subject plants compared to the conservatively bounding state of cracking assumed in the development of H*, the staff and the affected licensees concluded that implementation of H* for an interim period of up to two operating cycles would not impair assurance of SG tube integrity. Accordingly, the above LARs were revised as interim LARs. The staff has approved these interim LARs for 11 plants to date including, for example, Vogtle Unit Nos. 1 and 2 (Reference 12). The interim LAR for Salem Unit No. 1 is very similar to that approved for the Vogtle units.

3.0 REGULATORY EVALUATION

The Commission's regulatory requirements related to the content of the TSs are set forth in Title 10 of the *Code of Federal Regulations* (10 CFR) Section 50.36, "Technical specifications." This regulation requires that the TSs include items in the following five specific categories: (1) safety limits, limiting safety system settings, and limiting control settings; (2) limiting conditions for operation (LCOs); (3) surveillance requirements; (4) design features; and (5) administrative controls. The regulation does not specify the particular requirements to be included in a plant's TSs. As stated in 10 CFR 50.36(c)(5), "[a]dministrative controls are the provisions relating to organization and management, procedures, recordkeeping, review and audit, and reporting necessary to assure the operation of the facility in a safe manner." Programs established by the licensee, including the SG program, are listed in the administrative controls section of the TSs to operate the facility in a safe manner. For Salem Unit No. 1, the SG program requirements, including requirements for SG tube inspection and repair, are in TS 6.8.4.i, while the reporting requirements for the SG Program are in TS 6.9.1.10.

The TSs for all pressurized-water reactor (PWR) plants require that an SG program be established and implemented to ensure that SG tube integrity is maintained. For Salem Unit No. 1, SG tube integrity is maintained by meeting the performance criteria specified in TS 6.8.4.i.b for structural and leakage integrity, consistent with the plant design and licensing basis. Technical specification 6.8.4.i.a requires that a condition monitoring assessment be performed during each outage in which the SG tubes are inspected, to confirm that the performance criteria are being met. Technical specification 6.8.4.i.d includes provisions regarding the scope, frequency, and methods of SG tube inspections. These provisions require that the inspections be performed with the objective of detecting flaws of any type that may be present along the length of a 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. The applicable tube repair criteria, specified in TS 6.8.4.i.c., are that tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40 percent of the nominal wall thickness shall be plugged, unless the tubes are permitted to remain in service through application of the alternate repair criteria provided in TS 6.8.4.i.

The SG tubes are part of the reactor coolant pressure boundary (RCPB) and isolate fission products in the primary coolant from the secondary coolant. For the purposes of this safety evaluation, SG tube integrity means that the tubes are capable of performing this safety function in accordance with the plant design and licensing basis. The General Design Criteria (GDC) in Appendix A to 10 CFR Part 50 state that the RCPB shall have "an extremely low probability of abnormal leakage...and of gross rupture" (GDC 14), "shall be designed with sufficient margin" (GDC 15 and 31), shall be of "the highest quality standards practical" (GDC 30), and shall be designed to permit "periodic inspection and testing...to assess...structural and leaktight integrity" (GDC 32).

As discussed in Section 3.1 of the Salem Updated Final Safety Analysis Report (UFSAR), the GDC followed in the design of Salem Unit Nos. 1 and 2 are the Atomic Industrial Forum (AIF) version, as published in a letter to the Atomic Energy Commission (AEC) from E. A. Wiggin, AIF, dated October 2, 1967. As also discussed in Section 3.1 of the UFSAR, in addition to the AIF GDC, the Salem units were designed to comply with the intent of the AEC's proposed GDC dated July 1967. Section 3.1.2 of the UFSAR provides a discussion of Salem's conformance with the AEC proposed GDCs. Section 3.1.3 of the UFSAR also states that the design of the Salem units conforms to the intent of Appendix A to 10 CFR Part 50 (with several exceptions as discussed in this section of the UFSAR). The UFSAR does not list any exceptions to GDCs 14, 15, 30, 31, or 32.

The NRC's regulations in 10 CFR 50.55a specify that components, which are part of the RCPB, must meet the requirements for Class 1 components in Section III of the American Society of Mechanical Engineers *Boiler and Pressure Vessel Code* (ASME Code), except as provided in 10 CFR 50.55a(c)(2), (3), and (4). Section 50.55a further requires that throughout the service life of PWR facilities (like Salem Unit No. 1), ASME Code Class 1 components meet the Section XI requirements of the ASME Code to the extent practical, except for design and access provisions, and pre-service examination requirements. This requirement includes the inspection and repair criteria of Section XI of the ASME Code. The Section XI requirements pertaining to in-service inspection of SG tubing are augmented by additional requirements in the TSs.

As part of the plant's licensing basis, applicants for PWR licenses are required to analyze the consequences of postulated design-basis accidents (DBA), such as a SG tube rupture and a main steam line break (MSLB). These analyses consider primary-to-secondary leakage that may occur during these events and must show that the offsite radiological consequences do not exceed the applicable limits of the 10 CFR Part 100.11 accident source term, GDC 19 for control room operator doses (or some fraction thereof as appropriate to the accident), or the NRC-approved licensing basis (e.g., a small fraction of these limits). No accident analyses for Salem Unit No. 1 are being changed because of the proposed amendment and, thus, no radiological consequences of any accident analysis are being changed. The use of the proposed alternate repair criteria does not impact the integrity of the SG tubes, and the SG tubes, therefore, still meet the intent of the GDC in Appendix A to 10 CFR Part 50, and the requirements for Class 1 components in Section III of the ASME Code. The proposed changes maintain the accident analyses and consequences that the NRC has reviewed and approved for the postulated DBAs for SG tubes.

The proposed amendment eliminates TS wording relating to the previously-approved interim H* amendment (Reference 10), since that amendment applied to only refueling outage 18 and the subsequent operating cycle and is no longer in effect. The proposed amendment establishes a new interim amendment that exempts the portion of tubing located below 13.1 inches below the top of the tubesheet (TTS) from the TS SG tube inspection and repair limit requirements. Tubes with service-induced flaws located in the portion of the tube from the TTS to 13.1 inches below the TTS shall be plugged upon detection. The proposed amendment would be applicable to refueling outage 20 (spring 2010) and the subsequent operating cycles until the next scheduled SG tube inspection, which cannot extend beyond refueling outage 22 pursuant to TS 6.8.4.i.d.2. The proposed amendment is similar to that approved recently for the Vogtle units (Reference 12) and other units.

4.0 TECHNICAL EVALUATION

4.1 Proposed TS Changes

TS 6.8.4.i.c currently reads 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 repair criteria are applicable only for Refueling Outage 18 and the subsequent operating cycle: In lieu of the 40% of the nominal wall thickness 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.

TS 6.8.4.i.c. would be revised to read 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 shall be applied as an alternative to the 40 percent depth based criteria:
>
> 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 currently reads 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. 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 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 tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

1. [No change/Not shown]

2. [No change/Not shown]

3. If crack indications are found in any SG tube, 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.

TS 6.8.4.i.d would be revised to read 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.

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. [No change/Not shown]

2. [No change/Not shown]

3. If crack indications are found in 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.

TS 6.9.1.10 currently reads as follows:

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. – g. [No change/Not shown]

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 requirements are 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.

TS 6.9.1.10 would be revised to replace items h and i and add new item j as follows:

> Reporting requirements h, i and j are applicable to 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 preceding 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.

4.2 <u>Technical Evaluation</u>

The tube-to-tubesheet (T/TS) joints are part of the pressure boundary between the primary and secondary systems. Each T/TS joint consists of the tube, which is hydraulically expanded against the bore of the tubesheet, the T/TS weld located at the tube end, and the tubesheet. The joints were designed in accordance with the ASME Code, Section III, as welded joints, not as friction joints. The T/TS welds were designed to transmit the tube end-cap pressure loads, during normal operating and DBA conditions, from the tubes to the tubesheet with no credit taken for the friction developed between the hydraulically-expanded tube and the tubesheet. In addition, the welds serve to make the joints leak-tight.

This design basis is a conservative representation of how the T/TS joints actually work, since it conservatively ignores the role of friction between the tube and tubesheet in reacting with the tube end-cap loads. The initial hydraulic expansion of the tubes against the tubesheet produces an "interference fit" between the tubes and the tubesheet; thus, producing a residual contact pressure (RCP) between the tubes and tubesheet, which acts normally to the outer surface of the tubes and the inner surface of the tubesheet bore holes. Additional contact pressure between the tubes and tubesheet is induced by operational conditions as will be discussed in detail below. The amount of friction force that can be developed between the outer tube surface and the inner surface of the tubesheet bore is a direct function of the contact pressure between the tube and tubesheet times the applicable coefficient of friction.

To support the proposed TS changes, the licensee's contractor, Westinghouse, has defined a parameter called H* to be that distance below the top of the tubesheet over which sufficient frictional force, with acceptable safety margins, can be developed between each tube and the tubesheet under tube end-cap pressure loads associated with normal operating and DBA conditions to prevent significant slippage or pullout of the tube from the tubesheet, assuming the tube is fully severed at the H* distance below the top of the tubesheet. For Salem Unit No. 1, the proposed H* distance is 13.1 inches. Given that the frictional force developed in the T/TS joint over the H* distance is sufficient to resist the tube end-cap pressure loads, it is the licensee's and Westinghouse's position that the length of tubing between the H* distance and the T/TS weld is not needed to resist any portion of the tube end-cap pressure loads. Thus, the licensee is proposing to change the TSs to not require inspection of the tubes below the H* distance and to exclude tube flaws located below the H* distance (including flaws in the T/TS weld) from the application of the TS tube repair criteria. Under these changes, the T/TS joint would now be treated as a friction joint extending from the top of the tubesheet to a distance below the top of the tubesheet equal to H* for purposes of evaluating the structural and leakage integrity of the joint.

The regulatory standard by which the NRC staff has evaluated the subject license amendment is that the amended TSs should continue to ensure that tube integrity will be maintained consistent with the current design basis, as defined in the UFSAR. This includes maintaining structural safety margins consistent with the structural performance criteria in TS 6.8.4.i.b.1 discussed in Section 4.2.1.1 below. In addition, this includes limiting the potential for accident-induced primary-to-secondary leakage to values that do not exceed the accident-induced leakage performance criteria in TS 6.8.4.i.b.2, which are consistent with values assumed in the UFSAR accident analyses. Maintaining tube integrity in this manner ensures that the amended TSs are in compliance with all applicable regulations. The staff's evaluation of joint structural integrity and accident-induced leakage integrity is discussed in Sections 4.2.1 and 4.2.2 of this safety evaluation, respectively.

4.2.1 Joint Structural Integrity

4.2.1.1 Acceptance Criteria

Westinghouse has conducted extensive analyses to establish the necessary H* distance to resist pullout under normal operating and DBA conditions. The NRC staff finds that pullout is the structural failure mode of interest since the tubes are radially constrained against axial fishmouth rupture by the presence of the tubesheet. The axial force which could produce pullout derives from the pressure end-cap loads due to the primary-to-secondary pressure differentials associated with normal operating and DBA conditions. Westinghouse determined the needed H* distance on the basis of maintaining a factor of three against pullout under normal operating conditions and a factor of 1.4 against pullout under DBA conditions. The staff finds that these are the appropriate safety factors to apply to demonstrate structural integrity. These safety factors are consistent with the safety factors embodied in the structural integrity performance criteria in TS 6.8.4.i.b.1 and with the design basis including the stress limit criteria in the ASME Code, Section III.

4.2.1.2 T/TS Interaction Model

The resistance to pullout is the axial friction force developed between the expanded tube and the tubesheet over the H* distance. The friction force is a function of the radial contact pressure between the expanded tube and the tubesheet. Westinghouse used classical thick-shell equations to model the interaction effects between the tubes and tubesheet under various pressure and temperature conditions for purposes of calculating contact pressure (T/TS interaction model). For each tube, the tubesheet was modeled as an equivalent cylinder.

The thickness of this equivalent cylinder was calculated to provide a stiffness equivalent to the actual tubesheet geometry in terms of the amount of tubesheet bore radial displacement that is associated with a given amount of radial pressure on the surface of the bore. Two-dimensional (2-D) finite element analyses of portions of the perforated tubesheet geometry were used to determine the thickness of the equivalent tubesheet cylinder that provided the necessary stiffness, as a function of tube location within the bundle. These analyses directly modeled a spectrum of possibilities concerning the pressure loads acting on nearby bore surfaces, instead of employing a beta factor adjustment as was done to support previous H* amendment requests submitted prior to 2008. Based on its review, the NRC staff concludes that the equivalent tubesheet cylinder thicknesses calculated by Westinghouse are conservative since they provide for lower bound stiffness estimates, leading to lower (conservative) estimates of contact pressure and resistance to pullout.

The shell model representing the tube was used to determine the relationship between the tube outer surface radial displacement and the applied axial end-cap load (due to the primary-to-secondary pressure differential), primary pressure acting on the tube inner surface, crevice pressure[1] acting on the tube outer surface, contact pressure between the tube and tubesheet bore, and tube thermal expansion. However, the equivalent shell model representing the tubesheet was used only to determine the relationship between the tubesheet bore surface radial displacement with the applied crevice pressure and contact pressure. Radial displacements of the tubesheet bore surfaces are also functions of the primary pressure acting on the primary face of the tubesheet and SG channel head, secondary pressure acting on the secondary face of the tubesheet and SG shell, and the temperature distribution throughout the entire lower SG assembly. These displacements are a function of tube location within the tube bundle and, also, a function of axial location within the tubesheet. To calculate these displacements, 3-D finite element finite analyses were performed. The NRC staff's evaluation of these finite element analyses is provided in Section 4.2.1.3, below. The tubesheet bore radial displacements from the 3-D finite element analyses were added to those from the tubesheet equivalent shell model to yield the total displacement of the tubesheet bore surface as a function of tube radial and axial location.

The reference T/TS interaction model (Reference 2) assumes as an initial condition that each tube is fully expanded against the tubesheet bore such that the outer tube surface is in contact with the inner surface of the tubesheet bore under room temperature, atmospheric pressure conditions, with zero RCP associated with the hydraulic expansion process. The NRC staff finds the assumption of zero RCP in the reference analysis to be a very conservative assumption.

The thick shell equations used in the T/TS interaction model allow calculation of the tube radial displacements and the tubesheet equivalent cylinder radial displacements for a given set of pressure and temperature conditions. Under normal operational and DBA pressures and temperatures, the tube outer surface undergoes a higher radial displacement than the tubesheet bore surface if interaction between the tube and tubesheet is ignored. Because T/TS interaction effects demand continuity of displacements (i.e., the radial displacement of the tube outer surface equal the radial displacement of the bore surface) at each axial location, contact pressure of sufficient magnitude to ensure equal radial displacements is developed between the two surfaces and can be directly solved for. The NRC staff has reviewed the development of the

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1 Although the tubes are in tight contact with the tubesheet bore surfaces, surface roughness effects are conservatively assumed to create interstitial spaces, which are effectively crevices, between these surfaces. See Section 4.2.1.4 for more information.

T/TS interaction model and finds that it conservatively approximates the actual T/TS interaction effects and the resulting contact pressures.

The classical thick-shell equations used in the interaction model were developed for cylindrical shells whose geometry and applied loads are uniform along the cylindrical axis. As discussed above, radial deflections of the tubesheet bores are non-uniform from the top to the bottom of the tubesheet, due to the temperature and pressure loadings acting on the various components of the SG lower assembly. In addition, the crevice pressure may vary in the axial direction as discussed below. The interaction model essentially divides the T/TS joint into a series of horizontal slices, where each slice is assumed to behave independently of the slices above and below. The NRC staff concludes this to be conservative since it adds radial flexibility to the T/TS joint leading to lower contact pressures and tube pullout resistance.

The resisting force to the applied end-cap load, which is developed over each incremental axial distance from the top of the tubesheet, is the average contact pressure over that incremental distance times the tubesheet bore surface area (equal to the tube outer diameter surface area) over the incremental axial distance times the coefficient of friction. The NRC staff reviewed the coefficient of friction used in the analysis and judges it to be a reasonable lower bound (conservative) estimate. The H* distance for each tube was determined by integrating the incremental friction forces from the top of the tubesheet to the distance below the top of the tubesheet where the friction force integral equaled the applied end-cap load times the appropriate safety factor as discussed in Section 4.2.1.1.

In summary, the NRC staff has evaluated the T/TS interaction model and finds it to be a reasonable and conservative approach for the calculation of H* distances.

4.2.1.3 3-D Finite Element Analysis

A 3-D finite element analysis of the lower SG assembly (consisting of the lower portion of the SG shell, the tubesheet, the channel head, and the divider plate separating the hot and cold leg inlet plenums inside the channel head) was performed by Westinghouse to calculate the diameter changes of the tubesheet bore surfaces due to primary pressure acting on the primary face of the tubesheet and SG channel head, secondary pressure acting on the secondary face of the tubesheet and SG shell, and the temperature distribution throughout the entire lower SG assembly. These calculated diameter changes tended to be non-uniform around the circumference of the bore. The thick shell equations used in the T/TS interaction model are axisymmetric. Thus, the non-uniform diameter change from the 3-D finite element analyses had to be adjusted to an equivalent uniform value before it could be used as input to the T/TS interaction analysis. A 2-D plane stress finite element model was used to define a relationship for determining a uniform diameter change that would produce the same change to average T/TS contact pressure as would the actual non-uniform diameter changes from the 3-D finite element analyses. In Reference 13, Westinghouse identified a difficultly in applying this relationship to Model D5 SGs. In reviewing the reasons for this difficulty, the NRC staff developed questions relating to the conservatism of the relationship and whether the tubesheet bore displacement eccentricities are sufficiently limited such as to ensure that T/TS contact is maintained around the entire tube circumference. However, responses to staff questions provided in Reference 8 did not provide sufficient information to allow the staff to reach a conclusion on these matters relating to tubesheet bore displacement eccentricity such as to support a permanent amendment. For this reason, the license is proposing an interim H* amendment applicable only to Salem Unit No. 1 refueling outage 20 and the subsequent operating cycles until the next scheduled inspection. Section 4.2.4 provides the staff's evaluation of the interim H* amendment request in light of the open issue relating to tubesheet bore displacement eccentricity. As described in Section 4.2.4, there is sufficient information to enable the staff to evaluate the proposed interim amendment.

This 3-D finite element analysis replaces the 2-D axisymmetric finite element analyses used to support H* amendment requests submitted prior to 2008. The NRC staff finds that the 3-D analysis adequately addresses a concern cited by the staff in Reference 11 concerning the validity of the axisymmetric model to conservatively bound significant non-axisymmetric features of the actual tubesheets. These non-axisymmetric features include the solid (non-bored) portion of the tubesheet between the hot and cold leg sides, and the divider plate which acts to connect the solid part of the tubesheet to the channel head.

Some non-U.S. units have experienced cracks in the weld between the divider plate and the stub runner attachment on the bottom of the tubesheet. Should such cracks ultimately cause the divider plate to become disconnected from the tubesheet, tubesheet vertical and radial displacements under operational conditions could be significantly increased relative to those for an intact divider plate weld. Although the industry believes that there is little likelihood that cracks such as those seen abroad could cause a failure of the divider plate weld, the 3-D finite element analysis conservatively considered both the case of an intact divider plate weld and a detached divider plate weld to ensure a conservative analysis. The case of a detached divider plate weld was found to produce the most limiting H* values.

Separate 3-D finite element analyses were conducted for each loading condition considered (i.e., normal operating conditions, MSLB, feedwater line break (FLB)). The NRC staff finds that this adequately addresses (corrects) a significant source of error in analyses used by applicants to support permanent H* amendment requests submitted prior to 2008 and which were subsequently withdrawn (Reference 11).

4.2.1.4 Crevice Pressure Evaluation

As discussed above in footnote 1, the H* analyses postulate that interstitial spaces exist between the hydraulically expanded tubes and tubesheet bore surfaces. These interstitial spaces are assumed to act as crevices between the tubes and the tubesheet bore surfaces. The NRC staff finds that the assumption of crevices is conservative since the pressure inside the crevices acts to push against both the tube and the tubesheet bore surfaces, thus reducing contact pressure between the tubes and tubesheet.

For tubes which do not contain through-wall flaws within the thickness of the tubesheet, the pressure inside the crevice is assumed to be equal to the secondary system pressure. For tubes that contain through-wall flaws within the thickness of the tubesheet, a leak path is assumed to exist, from the primary coolant inside the tube, through the flaw, and up the crevice to the secondary system. Hydraulic tests were performed by Westinghouse on several tube specimens that were hydraulically expanded against tubesheet collar specimens to evaluate the distribution of the crevice pressure from a location where through-wall holes had been drilled into the tubes to the top of the crevice location. The T/TS collar specimens were instrumented at several axial locations to permit direct measurement of the crevice pressures. Tests were run for both normal operating and MSLB pressure and temperature conditions.

The NRC staff finds that the use of the drilled holes, rather than through-wall cracks, is conservative since it eliminates any pressure drop between the inside of the tube and the crevice at the hole location. This maximizes the pressure in the crevice at all elevations, thus reducing contact pressure between the tubes and tubesheet.

The crevice pressure data from these tests were used to develop a crevice pressure distribution as a function of normalized distance between the top of the tubesheet and the H* distance below the top of the tubesheet where the tube is assumed to be severed. These distributions were used to determine the appropriate crevice pressure for each axial slice of the T/TS interaction model. Based on its review of the tests and test results, the NRC staff finds the assumed crevice pressure distributions to be realistic and acceptable.

Because the crevice pressure distribution is assumed to extend from the H* location, where crevice pressure is assumed to equal primary pressure, to the top of the tubesheet, where crevice pressure equals secondary pressure, an initial guess as to the H* location must be made before solving for H* using the T/TS interaction model and 3-D finite element model. The resulting new H* estimate becomes the initial estimate for the next H* iteration.

4.2.1.5 H* Calculation Process

The calculation of H* in the reference analyses (Reference 2) consisted of the following steps for each loading case considered:

1. Perform initial H* estimate using the interaction and 3-D finite element models, assuming nominal geometric and material properties, and assuming that the tube is severed at the bottom of the tubesheet for purposes of defining the pressure distribution over the length of the T/TS crevice.

2. Add 0.3-inch adjustment to the initial H* estimate to account for uncertainty in the bottom of the tube expansion transition (BET) location relative to the TTS, based on an uncertainty analysis on the BET for Model F SGs conducted by Westinghouse.

3. For normal operating conditions only, add an additional adjustment to correct for the actual temperature distribution in the tubesheet compared to the linear distribution assumed in the finite element analysis. As discussed in Section 4.2.1.7, this step is conservative.

4. Steps 1 through 3 yield a so-called "mean" estimate of H*, which is deterministically based. Step 4 involves a probabilistic analysis of the potential variability of H*, relative to the mean estimate, associated with the potential variability of key input parameters for the H* analyses. This leads to a "probabilistic" estimate of H*, which includes the mean estimate.

5. Add a crevice pressure adjustment to the probabilistic estimate of H* to account for the crevice pressure distribution which results from the tube being severed at the final H* value, rather than at the bottom of the tubesheet. The value of this adjustment was determined iteratively.

The NRC staff's evaluation of the probabilistic analysis is provided in Section 4.2.1.7 of this safety evaluation. Regarding step 2, the staff did not review the Westinghouse BET uncertainty analysis. However, as described in Attachment 17 to PSEG's letter dated October 8, 2009, the licensee has committed to perform a one-time inspection of the actual BET locations (prior to entering Mode 4 during startup following refueling outage 20 in the spring of 2010) to confirm that there are no significant deviations from the assumed BET value. Any such deviations will be entered into the corrective actions program for disposition. The staff finds this to be acceptable, since the BET inspections are a one-time action that is reviewable during routine NRC regional oversight activities. Any deviations are likely to be small (less than a few tenths of an inch) and not likely to impact the overall conservatism of the proposed H* distance.

4.2.1.6 Acceptance Standard - Probabilistic Analysis

The purpose of the probabilistic analysis is to develop a safe H* distance that ensures with a probability of 0.95 that the population of tubes will retain margins against pullout consistent with criteria evaluated in Section 4.2.1.1 of this safety evaluation, assuming all tubes to be completely severed at their H* distance. The NRC staff finds this probabilistic acceptance standard is consistent with what the staff has approved previously and is acceptable. For example, the upper voltage limit for the voltage based tube repair criteria in NRC Generic Letter 95-05 (Reference 14) employs a consistent criterion. The staff also notes that use of the 0.95 probability criterion ensures that the probability of pullout of one or more tubes under normal operating conditions and conditional probability of pullout under accident conditions is well within tube rupture probabilities that have been considered in probabilistic risk assessments (References 15 and 16).

In terms of the confidence level that should be attached to the 0.95 probability acceptance standard, it is industry practice for SG tube integrity evaluations, as embodied in industry guidelines, to calculate such probabilities at a 50 percent confidence level. The Westinghouse recommended H* value of 11.2 inches in Reference 16 for Model F SGs is based on probabilistic estimates performed at a 50 percent confidence value. However, as discussed in Section 4.2.1.7, the NRC staff finds that the 13.1 inch H* value proposed by the licensee conservatively bounds an H* value based on probabilistic estimates performed at a 95 percent confidence value.

Another issue relating to the acceptance standard for the probabilistic analysis is determining what population of tubes needs to be analyzed. For accidents such as MSLB or FLB, the NRC staff and licensee both find that the tube population in the faulted SG is of interest, since it is the only SG population that experiences a large increase in the primary-to-secondary pressure differential. However, normal operating conditions were found to be the most limiting in terms of meeting the tube pullout margins in Section 4.2.1.1. For normal operating conditions, tubes in all SGs at the plant are subject to the same pressures and temperatures. Although there is not a consensus between the staff and industry on which population needs to be considered in the probabilistic analysis for normal operating conditions, and although the Westinghouse recommended H* value in Reference 2 is based on the population of just one SG, the staff finds that the 13.1 inch H* value proposed by the licensee conservatively bounds an H* value based on probabilistic estimates performed at a 95 percent confidence level for the entire tube population (i.e., for all SGs) at the plant, as discussed in Section 4.2.1.7 below.

4.2.1.7 Probabilistic Analyses

Sensitivity studies were conducted and demonstrated that H* was highly sensitive to the potential variability of the coefficients of thermal expansion (CTE) for the Alloy 600 tubing material and the SA-508 Class 2a tubesheet material. Given that no credit was taken in the reference H* analyses (Reference 2) for RCP associated with the tube hydraulic expansion process,[2] the sensitivity of H* to other geometry and material input parameters was judged by Westinghouse to be inconsequential and were ignored, with the exception of Young's modulus of elasticity for the tube and tubesheet materials. Although the Young's modulus parameters were included in the reference H* analyses sensitivity studies, these parameters were found to have a weak effect on the computed H*. Based on its review of the analysis models and its engineering judgment, the NRC staff concurs that the sensitivity studies adequately capture the input parameters which may significantly affect the value of H*. This conclusion is based, in part, on no credit being taken for RCP in the reference H* analyses.

These sensitivity studies were used to develop influence curves describing the change in H*, relative to the mean H* value estimate (see Section 4.2.1.5), as a function of the variability of each CTE parameter and Young's modulus parameter, relative to the mean values of CTE and Young's Modulus. Separate influence curves were developed for each of the four input parameters. The sensitivity studies showed that of the four input parameters, only the CTE parameters for the tube and tubesheet material had any interaction with one another. A combined set of influence curves containing this interaction effect were also created.

Two types of probabilistic analyses were performed independently. One was a simplified statistical approach utilizing a square root of the sum of the squares method and the other was a detailed Monte Carlo sampling approach. The NRC staff's review relies primarily on the Monte Carlo analysis which provides the more realistic treatment of uncertainties.

The NRC staff reviewed the implementation of probabilistic analyses in the reference analysis (Reference 2) to determine whether the H* influence curves had been conservatively treated. The staff concluded that the reference analysis was insufficient to support the amendment request. However, the licensee provided additional H* analyses, as documented in Reference 6, which addresses the staff's concern. These analyses made direct use of the H* influence curves in a manner the staff finds to be acceptable. To show that the proposed H* value in the subject LAR is conservative, the new analyses eliminated some of the conservatisms in the reference analyses as follows:

1. The reference analyses assumed that all tubes were located at the location in the tube bundle where the mean value estimate of H* was at its maximum value. The new analyses divided the tubes by sector location within the tube bundle and all tubes were assumed to be at the location in their respective sectors where the mean value estimate of H* was at its maximum value for that sector. The H* influence curves discussed above, developed for the most limiting tube location in the tube bundle, were conservatively used for all sectors. The staff concludes the sector approach in the new analyses to result in a more realistic, but still conservative H* estimate.

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2 Residual contact pressures are sensitive to variability of other input parameters.

2. The reference analyses add an incremental distance to H* to account for the actual distribution of temperature in the tubesheet under normal operating conditions versus the linear distribution assumed in the reference finite element analyses (see step 3 in Section 4.2.1.5 above). The new analyses included new finite element analyses which considered the actual distribution of temperature under normal operating conditions. The new analyses confirmed to the conservatism of the adjustment made in the reference analyses. The new finite element analyses, in conjunction with the sector analyses in item 1 above, result in an H* value which is significantly less than the proposed 13.1 inch H* based on a 0.95 probability/50 percent confidence, single SG basis. The NRC staff concludes that direct modeling of the actual temperature distribution in the tubesheet provides a more realistic, but still conservative estimate of H*, albeit on a 50 percent confidence, single SG basis. No H* estimate was provided on a 0.95 probability/95 percent confidence, all SG basis for this specific case. However, the sensitivity of the calculated H* when evaluated at a 95 percent versus 50 percent confidence level and when evaluated on an all SG versus single SG basis was determined by Westinghouse for other cases (Reference 17[3]). Based on its review of these sensitivities, the staff concludes that an H* value for this case based on a 0.95 probability/95 percent confidence, all SG basis is less than the proposed H* distance of 13.1 inches.

3. The reference analyses take no credit for RCP due to hydraulic expansion of the tubes against the respective tubesheet bores during SG manufacture. The new analyses include consideration of recently completed pullout tests and analyses. The licensee states that the tests confirm a significant level of RCP, and showed that within a small degree of slippage, the forces required to continue to move the tube by far exceeded the maximum pullout forces that could be generated under very conservative assumptions. The licensee finds that crediting this latest information, in conjunction with the sector analysis discussed in item 1 and the updated correction discussed in item 2 based on direct modeling of the temperature distribution in the tubesheet, leads to a further, significant reduction in the calculated H* value relative to values calculated in items 1 and 2. This information, including the latest pullout test data, has not been reviewed in detail by the NRC staff. However, the staff concludes that H* estimates that include no credit for RCP (e.g., the estimates in items 1 and 2 above) are very conservative, as evidenced by the high pullout forces needed to overcome the RCP.

The new analyses, items 1, 2 and 3 above, also address a question posed by the NRC staff in Reference 11 concerning the appropriate way to sample material properties for the tubesheet, whose properties are unknown but do not vary significantly for a given SG, in contrast to the tubes whose properties tend to vary much more randomly from tube to tube in a given SG. This issue was addressed by a staged sampling process where the tubesheet properties were sampled once and then held fixed, while the tube properties were sampled a number of times equal to the SG tube population. This process was repeated 10,000 times, and the maximum H* value from each repetition was rank ordered. The final H* value was selected from the rank ordering to reflect a 0.95 probability value at the desired level of confidence. The staff concludes that this approach addresses the staff's question in a realistic fashion and is acceptable.

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3 This evaluation was performed in a Westinghouse white paper submitted on the Vogtle docket by Southern Nuclear Operating Company. Although submitted on the Vogtle docket, the white paper is applicable to all Model F SGs, including those at Salem.

Based on items 1 and 2, and considering the significant conservatism associated with the assumption of zero RCP, the NRC staff concludes that the proposed H* distance of 13.1 inches for Salem Unit No. 1 ensures that all tubes will have acceptable pullout resistance for normal operating and DBAs, even with the conservative assumption that all tubes are severed at the H* distance.

As discussed in Attachment 17 to PSEG's letter dated October 8, 2009, the licensee will monitor for tube slippage as part of the SG inspection program. Under the proposed license amendment, TS 6.9.1.10.j will require that the results of slippage monitoring be included as part of the 180-day report required by TS 6.9.1.10. Technical specification 6.9.1.10.j will also require that should slippage be discovered, the implications of the discovery and corrective action shall be included in the report. The NRC staff finds that slippage is not expected to occur for the reasons discussed previously. In the unexpected event it should occur, it will be important to understand why it occurred so that the need for corrective action can be evaluated. The staff concludes the licensee's plan to monitor for slippage and the accompanying reporting requirements are acceptable.

4.2.1.8 Coefficient of Thermal Expansion

During operation, a large part of contact pressure in a SG tube-to-tubesheet joint is derived from the difference in the coefficients of thermal expansion (CTE) between the tube and tubesheet. As discussed in Section 4.2.1.7, the calculated value of H* is highly sensitive to the assumed values of these CTE parameters. However, CTE test data acquired by an NRC contractor, Argonne National Laboratory (ANL), suggested that CTE values may vary substantially from values listed in the ASME Code for design purposes. In Reference 11, the NRC staff highlighted the need to develop a rigorous technical basis for the CTE values, and their potential variability, to be employed in future H* analyses.

In response, Westinghouse had a subcontractor review the CTE data in question, determine the cause of the variance from the ASME Code CTE values, and provide a summary report (Reference 18). Analysis of the CTE data in question revealed that the CTE variation with temperature had been developed using a polynomial fit to the raw data, over the full temperature range from 75 °F to 1300 °F. The polynomial fit chosen resulted in mean CTE values that were significantly different from the ASME Code values from 75 °F to about 300 °F. When the raw data was reanalyzed using the locally weighted least squares regression (LOWESS) method, the mean CTE values determined were in good agreement with the established ASME Code values.

Westinghouse also formed a panel of licensee experts to review the available CTE data in open literature, review the ANL provided CTE data, and perform an extensive CTE testing program on Alloy 600 and SA-508 steel material to supplement the existing data base. Two additional sets of CTE test data (different from those addressed in the previous paragraph) had CTE offsets at low temperature that were not expected. Review of the test data showed that the first test, conducted in a vacuum, had proceeded to a maximum temperature of 700 °C, which changed the microstructure and the CTE of the steel during decreasing temperature conditions. As a result of the altered microstructure, the CTE test data generated in the second test, conducted in air, was also invalidated. As a result of the large "dead band" region and the altered microstructure, both data sets were excluded from the final CTE values obtained from the CTE testing program.

The test program included multiple material heats to analyze chemistry influence on CTE values and repeat tests on the same samples were performed to analyze for test apparatus influence. Because the tubes are strain-hardened when they are expanded into the tubesheet, strain-hardened samples were also measured to check for strain-hardening influence on CTE values.

The data from the test program were combined with the ANL data that were found by the licensee to be acceptable, and with the data obtained from the open literature search. A statistical analysis of the data uncertainties was performed by comparing deviations to the mean values obtained at the applicable temperatures. The correlation coefficients obtained indicated a good fit to a normal distribution, as expected. Finally, an evaluation of within-heat variability was performed due to increased data scatter at low temperatures. The within-heat variability assessment determined that the increase in data scatter was a testing accuracy limitation that was only present at low temperature. The CTE report is included as Appendix B to Reference 2.

The testing showed that the nominal ASME Code values for Alloy 600 and SA-508 steel were both conservative relative to the mean values from all the available data. Specifically, the CTE mean value for Alloy 600 was greater than the ASME Code value and the CTE mean value for SA-508 steel was smaller than the ASME Code value. Thus, the H* analyses utilized the ASME Code values as mean values in the H* analyses. The NRC staff finds this to be conservative because it tends to lead to an over-prediction of the expansion of the tubesheet bore and an under-prediction of the expansion of the tube, thereby resulting in an increase in the calculated H* distance. The statistical variances of the CTE parameters from the combined data base were utilized in the H* probabilistic analysis.

Based on its review of Westinghouse CTE program, the NRC staff concludes that the CTE values used in the H* analyses are fully responsive to the concerns stated in Reference 11 and are acceptable.

4.2.2 Accident-induced Leakage Considerations

Operational leakage integrity is assured by monitoring primary-to-secondary leakage relative to the applicable TS LCO limits in TS 3.4.6.2, "Reactor Coolant System Operational Leakage." However, it must also be demonstrated that the proposed TS changes do not create the potential for leakage during a DBA to exceed the accident leakage performance criteria in TS 6.8.4.i.b.2, including the leakage values assumed in the plant licensing basis accident analyses.

If a tube is assumed to contain a 100 percent through-wall flaw some distance into the tubesheet, a potential leak path between the primary and secondary systems is introduced between the hydraulically expanded tubing and the tubesheet. The leakage path between the tube and tubesheet has been modeled by the licensee's contractor, Westinghouse, as a crevice consisting of a porous media. Using Darcy's model for flow through a porous media, the leak rate is proportional to differential pressure and inversely proportional to flow resistance. Flow resistance is a direct function of viscosity, loss coefficient, and crevice length.

Westinghouse performed leak tests of tube-to-tubesheet joint mockups to establish loss coefficient as a function of contact pressure. A large amount of data scatter, however, precluded quantification of such a correlation. In the absence of such a correlation, Westinghouse has developed a leakage factor relationship between accident-induced leak rate and operational leakage rate, where the source of leakage is from flaws located at or below the H* distance. Using the Darcy model, the leakage factor for a given type accident is the product of four quantities. The first quantity is ratio of the maximum primary-to-secondary pressure difference during the accident divided by that for normal operating conditions. The second quantity is the ratio of viscosity under normal operating primary water temperature divided by viscosity under the accident condition primary water temperature. The third quantity is the ratio of crevice length under normal operating conditions to crevice length under accident conditions. This ratio equals 1, provided it can be shown that positive contact pressure is maintained along the entire H* distance for both conditions. The fourth quantity is the ratio of loss coefficient under normal operating conditions to loss coefficient under the accident condition. Although the absolute value of these loss coefficients isn't known, Westinghouse has assumed that the loss coefficient is constant with contact pressure such that the ratio is equal to 1. The NRC staff agrees that this is a conservative assumption, provided there is a positive contact pressure for both conditions along the entire H* distance and provided that contact pressure increases at each axial location along the H* distance when going from normal operating to accident conditions. Both assumptions were confirmed to be valid in the H* analyses.

Leakage factors were calculated by Westinghouse for DBAs exhibiting a significant increase in primary-to-secondary pressure differential, including MSLB, FLB, locked rotor, and control rod ejection. The design basis FLB heat-up transient was found to exhibit the highest leakage factor, 2.16, meaning that it is the transient expected to result in the largest increase in leakage relative to normal operating conditions.

In Attachment 17 to PSEG's letter dated October 8, 2009, the licensee provided the following information that describes how the leakage factor will be used to satisfy TS 6.8.4.i.a for condition monitoring and TS 6.8.4.i.b.2 regarding performance criteria for accident-induced leakage:

> For the condition monitoring (CM) assessment, the component of operational leakage from the prior cycle from below the H* distance will be multiplied by a factor of 2.16 and added to the total accident 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 accident induced 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. An administrative limit will be established to not exceed the calculated value (Salem Unit 1).

The NRC staff finds this methodology acceptable, since it provides further assurance, in addition to the licensee's operational leakage monitoring processes, that accident-induced SG tube leakage will not exceed values assumed in the licensing bases accident analyses. The staff finds that the leakage factor of 2.16 conservatively bounds the increase in leakage from locations below the H* distance that may be induced by accident conditions relative to leakage from the same locations under normal operating conditions.

4.2.3 Proposed Change to TS 6.9.1.10, "Steam Generator Tube Inspection Report"

The NRC staff has reviewed the proposed new reporting requirements and finds that they, in conjunction with existing reporting requirements, are sufficient to allow the staff to monitor the condition of the SG tubing as part of its review of the 180-day inspection reports. Based on this conclusion, the staff finds that the proposed new reporting requirements are acceptable.

4.2.4 Technical Bases for Interim H* Amendment

The proposed H* value is based on the conservative assumption that all tubes in all SGs are severed at the H* location. This is a bounding, but necessary assumption for purposes of supporting a permanent H* amendment because the tubes will not be inspected below the H* distance for the remaining life of the SGs, which may range up to 30 years from now depending on the plant, and because the tubes are susceptible to stress corrosion cracking below the H* distance. In addition, the proposed H* distance conservatively takes no credit for RCP associated with the tube hydraulic expansion process.

As discussed in Section 4.2.1.3, the NRC staff does not have sufficient information to determine whether the tubesheet bore displacement eccentricity has been addressed in a conservative fashion. Thus, in spite of the significant conservatisms embodied in the proposed H* distance, the staff is unable to conclude at this time that the proposed H* distance is, on net, conservative from the standpoint of ensuring that all tubes will retain acceptable margins against pullout (i.e., structural integrity) and acceptable accident leakage integrity for the remaining lifetime of the SGs, assuming all tubes to be severed at the H* location. However, the licensee is requesting an interim amendment that is applicable to the upcoming inspections during refueling outage 20 (spring 2010) and over the subsequent operating cycles to the next scheduled inspection (not exceeding two operating cycles) rather than an amendment that is applicable to the remaining life of the plant. The staff finds that assuming all tubes will be severed at the H* distance over the next operating cycle to be unrealistic and that the proposed H* distance is conservative for the next operating cycle for the reasons cited below.

From a fleet-wide perspective (for all Westinghouse plants with tubes fabricated from thermally treated Alloy 600), the NRC staff has observed from operating experience that the extent of cracking is at an early stage in terms of the number of tubes affected by cracking below the H* distance and the severity of cracks, compared to the idealized assumption that all tubes are severed at the H* distance. Most of these cracks occur in the lower-most 1 inch of tubing, which is a region of relatively high residual stress associated with the 1-inch tack roll expansion in that region. Although the extent of cracking can be expected to increase with time, it is the staff's judgment based on experience that it will continue to limited to a small percentage of tubes, mostly near the tube ends, over the next operating cycle. The staff's observations are based on the review of SG tube inspection reports from throughout the PWR fleet. These reports are reviewed and the staff's conclusions are documented after each SG tube inspection. Reference 19 provides a recent example of such a review by the staff for Salem Unit No. 1.

For Salem Unit No. 1, no crack indications were found during the most recent SG inspections in the spring of 2007, although the NRC staff notes that few tubes were inspected in the tubesheet region. However, the Salem Unit No. 1 SGs have accumulated relatively limited service time and operate at a relatively low hot leg temperature compared to the units discussed above which have experienced some cracks. Thus, the staff concludes that any undetected cracking in the tubesheet region at Salem Unit No. 1 would be expected to be very limited and well within the envelope of industry experience with similar units.

The NRC staff concludes that there is sufficient conservatism embodied in the proposed H* distances to ensure acceptable margins against tube pullout for at least one operating cycle for the reasons discussed above. The staff also concludes there is reasonable assurance during the next inspection cycle that any potential accident-induced leakage will not exceed the TS performance criteria for accident-induced leakage. This reflects current operating experience trends that cracking below the H* distance is occurring predominantly in the tack roll region near the bottom of the tube. At this location, it is the staff's judgment that the total resistance to primary-to-secondary leakage will be dominated by the resistance of any "crevice" in the roll expansion region (due to very high T/TS contact pressures in this region), such that the leakage factors discussed in Section 4.2.2 will remain conservative even should there be a loss of T/TS contact near the TTS due to tubesheet bore eccentricity effects.

4.2.5 Technical Evaluation Conclusion

The NRC staff finds that the proposed amendment request acceptably addresses all issues identified by the staff in Reference 11 relating to H* amendment requests submitted prior to 2008 (which were subsequently withdrawn). However, the staff does not have sufficient information to determine whether the tubesheet bore displacement eccentricity has been addressed in a conservative fashion and, thus, the staff does not have an adequate basis to approve a permanent H* amendment. Based on discussion of these concerns between the NRC staff and the industry, the licensee has submitted an interim amendment request, applicable only to Salem Unit No. 1 refueling outage 20 and the subsequent operating cycles (2 cycles maximum) until the next scheduled SG inspection.

Notwithstanding any potential non-conservatism in the calculated H* distance which may be associated with the eccentricity issue, the NRC staff concludes that, given the current state of the tubes, there is sufficient conservatism embodied in the proposed H* distances to ensure, for one operating cycle, that tube structural and leakage integrity will be maintained with structural safety margins consistent with the design basis and with leakage integrity within assumptions employed in the licensing basis accident analyses. Based on this finding, the NRC staff further concludes that the proposed amendment is acceptable.

5.0 STATE CONSULTATION

In accordance with the Commission's regulations, the New Jersey State official was notified of the proposed issuance of the amendment. The State official had no comments.

6.0 ENVIRONMENTAL CONSIDERATION

The amendment changes a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration, and there has been no public comment on such finding (75 FR 464). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

7.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (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.

8.0 REFERENCES

1. PSEG letter LR-N09-0232, "Salem Generating Station - Unit 1, License Amendment Request, Revision to Technical Specification 6.8.4.i, "Steam Generator (SG) Program," for One-Time (Interim) Alternate Repair Criteria (H*)," dated October 8, 2009 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML092960581).

2. Westinghouse Electric Company (WEC) report, WCAP-17071- NP (Non- Proprietary), Revision 0, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model F)," dated April 2009 (ADAMS Accession No. ML092960586). This is Attachment 5 of Reference 1.

3. Southern Nuclear Operating Company, Inc. (SNC), letter NL-09-0547, "Vogtle Electric Generating Plant, License Amendment Request to Revise Technical Specification (TS) Sections 5.5.9, "Steam Generator (SG) Program" and TS 5.6.10, "Steam Generator Tube Inspection Report" for Permanent Alternate Repair Criteria," dated May 19, 2009 (ADAMS Accession No. ML091470701).

4. NRC letter, "Vogtle Electric Generating Plant, Units 1 and 2, Request For Additional Information Regarding Steam Generator Program," dated July 10, 2009 (ADAMS Accession No. ML091880384).

5. NRC letter, "Vogtle Electric Generating Plant, Units 1 and 2, Request for Additional Information Regarding Steam Generator Program," dated August 5, 2009 (ADAMS Accession No. ML092150057).

6. WEC letter, LTR-SGMP-09-100 NP, "Response to NRC Request for Additional Information on H*; Model F and D5 Steam Generators," dated August 12, 2009. This is Attachment 8 of Reference 1.

7. Salem Unit 1 site specific response to RAI questions 21, 22, and 23. This is Attachment 10 of Reference 1.

8. WEC letter, LTR-SGMP-09-109 NP, "Response to NRC Request for Additional Information on H*; RAI#4; Model F and D5 Steam Generators," dated August 25, 2009. This is Attachment 12 of Reference 1.

9. PSEG letter LR-N06-0392, "Salem Generating Station - Unit 1, License Change Request S06-011, WCAP-16640, Steam Generator Alternate Repair Criteria (H*/B* Methodology)," dated October 2, 2006 (ADAMS Accession No. ML062920223).

10. NRC letter, "Salem Nuclear Generating Station, Unit No. 1, Issuance of Amendment Re: Steam Generator Alternate Repair Criteria," dated March 27, 2007 (ADAMS Accession No. ML070790081).

11. NRC letter, "Wolf Creek Generating Station - Withdrawal of License Amendment Request on Steam Generator Tube Inspections," dated February 28, 2008 (ADAMS Accession No. ML080450185).

12. NRC letter, "Vogtle Electric Generating Plant, Units 1 and 2, Issuance of Amendments Regarding Technical Specification (TS) Section 5.5.9, "Steam Generator Program," and TS 5.6.10, "Steam Generator Tube Inspection Report," for Interim Alternate Repair Criteria," dated September 24, 2009 (ADAMS Accession No. ML092170782).

13. WEC report, WCAP-17072-NP (Non-Proprietary), Revision 0, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model D5)," dated May 2009 (ADAMS Accession No. ML091670172).

14. NRC Generic Letter 95-05, "Voltage Based Alternate Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside Diameter Stress Corrosion Cracking," dated August 3, 1995 (ADAMS Accession No. ML031070113).

15. NUREG-0844, "NRC Integrated Program for the Resolution of Unresolved Safety Issues A-3, A-4, and A-5 Regarding Steam Generator Tube Integrity," dated September 1988 (ADAMS Accession No. ML082400710 - non-publicly available).

16. NUREG-1570, "Risk Assessment of Severe Accident-Induced Steam Generator Tube Rupture," dated March 1998 (ADAMS Accession No. ML070570094 - non-publicly available).

17. SNC letter NL-09-1317 dated August 28, 2009, transmitting WEC letter LTR-SGMP-09-104-NP Attachment, "White Paper on Probabilistic Assessment of H*" dated August 13, 2009 (ADAMS Accession No. ML092450029).

18. Nuclear Energy Institute letter dated July 7, 2008 (ADAMS Accession No. ML082100086), transmitting Babcock and Wilcox Canada LTD. letter 2008-06-PK-001, "Re-assessment of PMIC measurements for the determination of CTE of SA 508 steel," dated June 6, 2008 (ADAMS Accession No. ML082100097).

19. NRC letter, "Review of the Steam Generator Tube Inservice Inspection Report for Spring 2007, Salem Nuclear Generating Station, Unit No. 1, dated July 22, 2008 (ADAMS Accession No. ML081970092).

20. PSEG letter LR-N10-0066, "Supplement to License Amendment Request S09-04, Revision to Technical Specification 6.8.4.i, "Steam Generator (SG) Program," for One-

Time (Interim) Alternate Repair Criteria (H*)," dated February 25, 2010 (ADAMS Accession No. ML100680482).

Principal Contributor: E. Murphy

Date: March 29, 2010

March 29, 2010

Mr. Thomas Joyce
President and Chief Nuclear Officer
PSEG Nuclear
P.O. Box 236, N09
Hancocks Bridge, NJ 08038

SUBJECT: SALEM NUCLEAR GENERATING STATION, UNIT NO. 1, ISSUANCE OF AMENDMENT RE: STEAM GENERATOR INSPECTION SCOPE AND REPAIR REQUIREMENTS (TAC NO. ME2374)

Dear Mr. Joyce:

The Commission has issued the enclosed Amendment No. 294 to Facility Operating License No. DPR-70 for the Salem Nuclear Generating Station, Unit No. 1. This amendment consists of changes to the Technical Specifications (TSs) in response to your application dated October 8, 2009, as supplemented by letter dated February 25, 2010.

The amendment approves a one-time change to TS 6.8.4.i, "Steam Generator (SG) Program," regarding the SG tube inspection and repair required for the portion of the SG tubes passing through the tubesheet region. Specifically, for Salem Unit No. 1 refueling outage 20 (planned for spring 2010) and subsequent operating cycles until the next scheduled SG tube inspection, the amendment limits the required inspection (and repair if degradation is found) to the portions of the SG tubes passing through the upper 13.1 inches of the approximate 21-inch tubesheet region. In addition, the amendment revises TS 6.9.1.10, "Steam Generator Tube Inspection Report," to provide reporting requirements specific to the one-time change.

A copy of our safety evaluation is also enclosed. Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,
/ra/
Richard B. Ennis, Senior Project Manager
Plant Licensing Branch I-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-272
Enclosures:
1. Amendment No. 294 to License No. DPR-70
2. Safety Evaluation

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Accession No.: ML100570452

OFFICE	LPL1-2/PM	LPL1-2/LA	CSGB/BC	ITSB/BC	OGC (NLO w/ comments)	LPL1-2/BC
NAME	REnnis	ABaxter	RTaylor	RElliott	MSmith	HChernoff
DATE	3/2/10	3/4/10	3/5/10	3/15/10	3/22/10	3/29/10