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

May 20, 2011

Mr. David A. Heacock
President and Chief Nuclear Officer
Virginia Electric and Power Company
Innsbrook Technical Center
5000 Dominion Boulevard
Glen Allen, VA 23060-6711

SUBJECT: SURRY POWER STATION, UNIT NO. 2, ISSUANCE OF AMENDMENT REGARDING TECHNICAL SPECIFICATION CHANGE TO SECTIONS 6.4.Q, "STEAM GENERATOR (SG) PROGRAM" AND 6.6.A.3 "STEAM GENERATOR TUBE INSPECTION REPORT" (H*) (TAC NO. ME5368)

Dear Mr. Heacock:

The U.S. Nuclear Regulatory Commission has issued the enclosed Amendment No. 273 to Renewed Facility Operating License No. DPR-37 for the Surry Power Station, Unit No. 2. The amendment changes the Technical Specifications (TSs) in response to your application dated December 16, 2010.

This amendment revises the inspection scope and repair requirements of TS Section 6.4.Q, "Steam Generator Program," and to the reporting requirements of TS Section 6.6.A.3, "Steam Generator Tube Inspection Report." The proposed changes would be applicable to Surry Unit 2 during Refueling Outage (RFO) 23 and the subsequent operating cycle. The proposed changes would establish temporary alternate repair criteria for portions of the Unit 2 SG tubes within the tubesheet, and would replace similar, existing criteria that were used in 2009 during the previous refueling outage, RFO 22.

A copy of the Safety Evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

Joel S Wiebe, for

Karen Cotton, Project Manager
Plant Licensing Branch II-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-281

Enclosures:
1. Amendment No. 273 to DPR-37
2. Safety Evaluation

cc w/encls: Distribution via Listserv

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

VIRGINIA ELECTRIC AND POWER COMPANY

DOCKET NO. 50-281

SURRY POWER STATION, UNIT NO. 2

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 273
Renewed License No. DPR-37

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

   A. The application for amendment by Virginia Electric and Power Company (the licensee) dated December 16, 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 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;

   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 3.B of Renewed Facility Operating License No. DPR-37 is hereby amended to read as follows:

(B) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 273, are hereby incorporated in the renewed 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 within 30 days.

FOR THE NUCLEAR REGULATORY COMMISSION

Gloria Kulesa, Chief
Plant Licensing Branch II-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes License No. DPR-37
and the Technical Specifications

Date of Issuance May 20, 2011

ATTACHMENT

TO LICENSE AMENDMENT NO. 273

RENEWED FACILITY OPERATING LICENSE NO. DPR-37

DOCKET NO. 50-281

Replace the following pages of the License and the Appendix A Technical Specifications (TSs) with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove Pages	Insert Pages
License	License
License No. DPR-37, page 3	License No. DPR-37, page 3
TSs	TSs
6.4-12	6.4-12
6.4-13	6.4-13
6.6-3	6.6-3
6.6-3a	6.6-3a

E. Pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

3. This renewed license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations: 10 CFR Part 20, Section 30.34 of 10 CFR Part 30, Section 40.41 of 10 CFR Part 40, Sections 50.54 and 50.59 of 10 CFR Part 50, and Section 70.32 of 10 CFR Part 70; and is subject to all applicable provisions of the Act and the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified below:

   A. Maximum Power Level

      The licensee is authorized to operate the facility at steady state reactor core power levels not in excess of 2587 megawatts (thermal).

   B. Technical Specifications

      The Technical Specifications contained in Appendix A, as revised through Amendment No. 273 , are hereby incorporated in this renewed license. The licensee shall operate the facility in accordance with the Technical Specifications.

   C. Reports

      The licensee shall make certain reports in accordance with the requirements of the Technical Specifications.

   D. Records

      The licensee shall keep facility operating records in accordance with the requirements of the Technical Specifications.

   E. Deleted by Amendment 54

   F. Deleted by Amendment 59 and Amendment 65

   G. Deleted by Amendment 227

   H. Deleted by Amendment 227

c. The operational LEAKAGE performance criterion is specified in TS 3.1.C and 4.13, "RCS Operational LEAKAGE."

3. 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 tube repair criteria shall be applied as an alternative to the 40% depth-based criteria:

   a. For Unit 1 during Refueling Outage 23 and the subsequent operating cycle and for Unit 2 during Refueling Outage 23 and the subsequent operating cycle, tubes with service-induced flaws located greater than 16.7 and 17.74 inches, respectively, 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 16.7 (Unit 1)/17.74 (Unit 2) inches below the top of the tubesheet shall be plugged upon detection.

4. 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 Unit 1 during Refueling Outage 23 and the subsequent operating cycle and for Unit 2 for Refueling Outage 23 and the subsequent operating cycle, portions of the tube greater than 16.7 and 17.74 inches, respectively, below 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 4.a, 4.b, and 4.c 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.

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

    b. 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.

    c. If crack indications are found in the 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.

5. Provisions for monitoring operational primary to secondary LEAKAGE.

b. The results of specific activity analysis in which the primary coolant exceeded the limits of Specification 3.1.D.4. In addition, the information itemized in Specification 3.1.D.4 shall be included in this report.

3. Steam Generator Tube Inspection Report

A report shall be submitted within 180 days after T_{avg} exceeds 200°F following completion of an inspection performed in accordance with the Specification 6.4.Q, Steam Generator (SG) Program. The report shall include:

a. The scope of inspections performed on each SG,
b. Active degradation mechanisms found,
c. Nondestructive examination techniques utilized for each degradation mechanism,
d. Location, orientation (if linear), and measured sizes (if available) of service induced indications,
e. Number of tubes plugged during the inspection outage for each active degradation mechanism,
f. Total number and percentage of tubes plugged to date,
g. The results of condition monitoring, including the results of tube pulls and in-situ testing,
h. The effective plugging percentage for all plugging in each SG,
i. For Unit 1 during Refueling Outage 23 and the subsequent operating cycle and for Unit 2 during Refueling Outage 23 and the subsequent operating cycle, 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, and

j. For Unit 1 during Refueling Outage 23 and the subsequent operating cycle and for Unit 2 during Refueling Outage 23 and the subsequent operating cycle, the calculated accident induced LEAKAGE rate from the portion of the tubes below 16.7 and 17.74 inches, respectively, 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 2.03 times the maximum operational primary to secondary LEAKAGE rate, the report should describe how it was determined.

k. For Unit 1 during Refueling Outage 23 and the subsequent operating cycle and for Unit 2 during Refueling Outage 23 and the subsequent operating cycle, the results of the monitoring for tube axial displacement (slippage). If slippage is discovered, the implications of the discovery and corrective action shall be provided.

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO RENEWED FACILITY OPERATING LICENSE NO. DPR-37

VIRGINIA ELECTRIC AND POWER COMPANY

SURRY POWER STATION, UNIT NO. 2

DOCKET NO. 50-281

1.0 INTRODUCTION

By letter dated December 16, 2010 (Agencywide Documents Access and Management System (ADAMS), Accession No. ML103550206) (Reference 1), Virginia Electric and Power Company (VEPCO, the licensee) submitted a request for changes to the Surry Power Station, Unit No. 2 (Surry Unit 2), Technical Specifications (TSs).

The request proposed changes to the inspection scope and repair requirements of TS Section 6.4.Q, "Steam Generator (SG) Program," and to the reporting requirements of TS Section 6.6.A.3, "Steam Generator Tube Inspection Report." The proposed changes would be applicable to Surry Unit 2 during Refueling Outage (RFO) 23 and the subsequent operating cycle. The proposed changes would establish temporary alternate repair criteria for portions of the Surry Unit 2 SG tubes within the tubesheet, and would replace similar, existing criteria that were used in 2009 during the previous refueling outage, RFO 22.

2.0 BACKGROUND

Surry Unit 2 has three Model 51F SGs each, which were designed and fabricated by Westinghouse. There are 3,342 thermally treated Alloy 600 (Alloy 600TT) tubes with a nominal outside diameter of 0.875 inches and a nominal wall thickness of 0.050 inches. The thermally treated tubes are hydraulically expanded for the full depth of the 21-inch thick tubesheet and are welded to the tubesheet at each tube end. Until the fall of 2004, no instances of stress corrosion cracking (SCC) affecting the tubesheet region of Alloy 600TT 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 2 (Catawba), which has Westinghouse Model D5 SGs. Like Surry Unit 2, the Catawba SGs use Alloy 600TT 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 (T/TS) 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 tubesheet drilling, by conditions such as drill bit wandering or chip gouging. The approximately 1-inch long tack expansion is made at each tube end and facilitates performing the T/TS 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 2, Byron Unit 2, Comanche Peak Unit 2, Surry Unit 2, Vogtle Unit 1, and Wolf Creek Unit 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 February 21, 2006, Wolf Creek Nuclear Operating Corporation (WCNOC), the licensee for Wolf Creek Generating Station, submitted a license amendment request (LAR) that would permanently limit the scope of inspections required for tubes within the tubesheet (Reference 2). The LAR was based on an analysis performed by Westinghouse that provided a technical basis for permanently limiting the scope of inspections required for tubes within the tubesheet. After three requests for additional information (RAIs) and several meetings with WCNOC, the Nuclear Regulatory Commission (NRC) staff informed WCNOC during a phone call on February 7, 2008, that it had not provided sufficient information to allow the NRC staff to review and approve the permanent LAR. WCNOC withdrew the LAR by letter dated February 14, 2008 (Reference 3). Other plants had submitted permanent LARs similar to that for Wolf Creek prior to 2008, which also were subsequently withdrawn. In a letter dated February 28, 2008 (Reference 4), 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.

After withdrawal of the initial round of permanent LARs submitted prior to 2008, the licensees and their contractor, Westinghouse, worked with the NRC staff to address the issues posed in Reference 4 about the technical analysis referred to as H*. The NRC and industry held public meetings (References 5, 6, and 7) and phone calls to discuss resolution of these issues. The permanent LAR received from the licensee on July 28, 2009 (Reference 8), resolved the issues identified by the NRC staff in Reference 4 but raised an additional technical issue that prevented approval of the permanent LAR. Responses to NRC staff RAIs were supplied in Reference 9, and the licensee modified its July 28, 2009 LAR (via Reference 10) to apply during RFO 22 and the subsequent operating cycle, instead of the permanent change originally requested.

The NRC staff approved the revised amendment in Reference 11. The accompanying safety evaluation (SE) concluded that the NRC staff did not have sufficient information to determine whether the tubesheet bore displacement eccentricity had been addressed in a conservative fashion and, thus, the NRC staff did not have an adequate basis to approve a permanent H* amendment at that time. The NRC staff further concluded that despite any potential non-conservatism in the calculated H* distance that may have been associated with the eccentricity issue, there was sufficient conservatism embodied in the proposed H* distance to ensure for at least one operating cycle (one fuel cycle) that tube structural and leakage integrity would be maintained with structural safety margins consistent with the design basis and with leakage integrity within assumptions employed in the licensing basis accident analyses, without undue risk to public health and safety.

Subsequent analyses by industry to address the NRC staff's concerns revealed that tubesheet bore eccentricity did not have a significant bearing on the outcome of the H* analyses. However, these analyses also revealed a significant shortcoming in how displacements from the 3-D finite element model of the lower SG assembly were being applied to the T/TS interaction model, which was based on thick shell equations. The industry developed a new T/TS interaction model to address this shortcoming and the H* analyses were updated accordingly. This more recent background is discussed in more detail as part of the NRC staff's technical evaluation in Section 4.0 of this SE. Details of these more recent analyses became available for NRC staff review too late to support applications for permanent H* amendments in the spring or fall of 2011. The licensee's request was for one cycle. For this reason, the subject amendment request by the licensee is for an interim H* amendment, applicable to RFO 23 and the subsequent operating cycle for Surry Unit 2.

3.0 REGULATORY EVALUATION

In Title 10 of the *Code of Federal Regulations* (10 CFR), Part 50, Section 50.36 "Technical specifications," the requirements related to the content of the TSs are established. Pursuant to 10 CFR 50.36, TSs are required to include items in the following five categories: (1) safety limits, limiting safety system settings, and limiting control settings; (2) limiting conditions for operation; (3) surveillance requirements; (4) design features; and (5) administrative controls.

In 10 CFR 50.36(c)(5), "Administrative 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 Surry Unit 2, the requirements for performing SG tube inspections and repair are in TS 6.4.Q, while the requirements for reporting the SG tube inspections and repair are in TS 6.6.A.3.

The TSs for all pressurized water reactor (PWR) plants include an SG program. For Surry Unit 2, SG tube integrity is maintained by meeting the performance criteria specified in TS 6.4.Q.2 for structural and leakage integrity, consistent with the plant design and licensing basis. TS 6.4.Q.1 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. TS 6.4.Q.4 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 T/TS weld at the tube inlet to the T/TS weld at the tube outlet, and that may satisfy the applicable tube repair criteria. The applicable tube repair criteria, specified in TS 6.4.Q.3., are that tubes found during 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 proposed alternate repair criteria provided in TS 6.4.Q.3.a.

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 SE, SG tube integrity means that the tubes are capable of performing this safety function in accordance with the plant design and licensing basis. Surry is a pre-General Design Criteria (GDC) plant but they meet the intent of the GDC without exception. The GDC in Appendix A to 10 CFR Part 50 provide regulatory requirements that are applicable to Surry Unit 2, and 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). Surry Unit 2 received construction permits prior to May 21, 1971, which is the date the GDC in Appendix A of 10 CFR Part 50 became effective. The licensee states it is in compliance with the intent of the current GDC and also meets the design criteria that were in effect when Surry Unit 2 was licensed. The licensee discusses how it meets the design criteria for Surry Unit 2 in Sections 4.1, 4.2, and 4.3 of the Updated Final Safety Analysis Report (UFSAR).

To this end, 10 CFR 50.55a specifies 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 Surry Unit 2), 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 preservice examination requirements. This requirement includes the inspection and repair criteria of Section XI of the ASME Code. The Section XI requirements pertaining to inservice inspection of SG tubing are augmented by additional requirements in the TSs.

As part of the plant's licensing bases, applicants for PWR licenses analyzed the consequences of postulated design-basis accidents (DBAs), 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 50.67 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 Surry Unit 2 are being changed 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 requirements 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.

License Amendments Nos. 267 and 266 are currently approved at Surry Units 1 and 2, respectively. The amendments modified TS 6.4.Q, "Steam Generator Program," and TS 6.6.A.3, "Steam Generator Tube Inspection Report," by incorporating interim alternate repair criteria and associated tube inspection and reporting requirements that are applicable during RFO 23 (Surry Unit 1) and RFO 22 (Surry Unit 2) and their respective subsequent operating cycles. The approved H* distance in Amendment Nos. 267 and 266 is 16.7 inches. The proposed subject amendment uses a revised H* distance of 17.74 inches that would be applicable only to Surry Unit 2 during RFO 23 (spring 2011) and the subsequent operating cycle. The 17.74-inch H* distance is slightly longer than the currently approved 16.7-inch H* distance, and is a result of the revised analyses, as discussed in Section 4.0.

4.0 TECHNICAL EVALUATION

Proposed Changes to the TSs

TS 6.4.Q. is being revised as follows (new text in underline and bold):

6.4.Q. Steam Generator Program

3. 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 tube repair criteria shall be applied as an alternative to the 40% depth based criteria:

   a. For Unit **1** during Refueling Outage **23** and the subsequent operating cycle and for Unit 2 during Refueling Outage 23 and the subsequent operating cycle, tubes with service-induced flaws located greater than 16.7 **and 17.74** inches, **respectively**, 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 16.7 **(Unit 1)/17.74 (Unit 2)** inches below the top of the tubesheet shall be plugged upon detection.

4. 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 outlet, and that may satisfy the applicable tube repair criteria. For Unit **1** during Refueling Outage **23** and the subsequent operating cycle and for Unit **2** during Refueling Outage 23 and the subsequent operating cycle, portions of the tube greater than 16.7 **and 17.74** inches, **respectively**, below 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 4.a, 4.b, and 4.c 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.

TS 6.6.A.3. is being revised as follows (new text in underline and bold):

6.6.A.3 Steam Generator Tube Inspection Report

A report shall be submitted within 180 days after T_{avg} exceeds 200 °F following completion of an inspection performed in accordance with Specification 6.4.Q, Steam Generator (SG) Program. The report shall include:

i. For Unit **1** during Refueling Outage **23** and the subsequent operating cycle and for Unit **2** during Refueling Outage 23 and the subsequent operating cycle, 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, and

j. For Unit **1** during Refueling Outage **23** and the subsequent operating cycle and for Unit **2** during Refueling Outage 23 and the subsequent operating cycle, the calculated accident induced leakage rate from the portion of the tubes below 16.7 **and 17.74** inches, **respectively**, 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 2.03 times the maximum operational primary to secondary LEAKAGE rate, the report should describe how it was determined;

k. For Unit **1** during Refueling Outage **23** and the subsequent operating cycle and for Unit **2** during Refueling Outage 23 and the subsequent operating cycle, the results of monitoring for tube axial displacement (slippage). If slippage is discovered, the implications of the discovery and corrective action shall be provided.

4.1 Technical Evaluation

The 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 Section III of the ASME Code 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. The axial force which could produce pullout comes from the primary-to-secondary pressure differentials associated with normal operating and DBA conditions, and is called the end cap load. 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 reducing 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 Surry Unit 2, the proposed H* distance is 17.74 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 TS 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.

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 integrity performance criteria in TS 6.4.Q.2.a, as discussed in Section 4.2.1 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 6.4.Q.2.b, 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 NRC staff's evaluation of joint structural integrity and accident-induced leakage integrity is discussed in Sections 4.2 and 4.3 of this SE, respectively.

4.2 <u>Joint Structural Integrity</u>

4.2.1 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 comes from the primary-to-secondary pressure differentials associated with normal operating and DBA conditions, and is called the end cap load. Westinghouse determined the needed H* distance on the basis of maintaining a safety factor of 3 against pullout under normal operating conditions and a safety factor of 1.4 against pullout under DBA conditions. The NRC 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 6.4.Q.2.a and with the design basis, including the stress limit criteria in Section III of the ASME Code.

4.2.2 3-D Finite Element Analysis

A detailed 3-D finite element analysis (FEA) 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 to calculate tubesheet displacements 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. The calculated tubesheet displacements were used as input to the T/TS interaction analysis evaluated in Section 4.2.3 below.

The tubesheet bore holes were not explicitly modeled. Instead, the tubesheet was modeled as a solid structure with equivalent material property values selected such that the solid model exhibited the same stiffness properties as the actual perforated tubesheet.

A number of FEA mesh enhancements in the tubesheet region have been made since the reference analysis (Reference 12) was performed. The mesh near the plane of symmetry (perpendicular to the divider plate) was revised to permit obtaining displacements parallel to the direction of the divider plate directly from the 3-D finite element model, for application (as displacement boundary conditions) to the edges of the square cell model discussed in Section 4.2.3.2. The mesh near the top of the tubesheet was enhanced to accommodate high temperature gradients in this area during normal operating conditions.

This 3-D FEA replaces the 2-D axisymmetric FEA 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 NRC staff in Reference 4 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 FEA 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. In the reference analyses (Reference 12), a factor was applied to the 3-D FEA results to account for a non-functional divider plate, based on earlier sensitivity studies performed with the 2-D axisymmetric FEA model of the lower SG assembly. The 3-D FEA model now assumes the upper 5 inches of the divider plate to be non-existent. The NRC staff finds this further improves the accuracy of the 3-D FEA for the assumed condition of a non-functional divider plate.

Separate 3-D FEA analyses were conducted for each loading condition considered (i.e., normal operating conditions, MSLB, feedwater line break (FLB)), rather than scaling unit load analyses to prototypic conditions as was done in analyses prior to 2008. The NRC staff finds that this 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 4). In addition, the temperature distributions throughout the lower SG assembly, including the tubesheet region, were calculated directly in the 3-D FEA from the assumed plant temperature conditions (e.g., from the assumed primary and secondary water temperatures) for each operating condition.

4.2.3 T/TS Interaction Model

4.2.3.1 Thick Shell 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. In the analysis (Reference 12) for the interim H* amendment issued on November 5, 2009, for Surry Unit 2 (Reference 11), 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). Calculated displacements from the 3-D FEA of the lower tubesheet assembly (see Section 4.2.2 above) were applied to the thick shell model as input to account for the increment of tubesheet bore diameter change caused by 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. However, the tubesheet bore diameter change from the 3-D FEA tended to be non-uniform (eccentric) around the bore circumference. The thick shell equations used in the T/TS interaction model are axisymmetric. Thus, the non-uniform diameter change from the 3-D FEA 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 12, Westinghouse identified a difficultly in applying this relationship to Model D5 SGs under MSLB conditions. 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. This concern was applicable to all SG models with Alloy 600TT tubing. Responses to the NRC staff's questions were insufficient and did not allow the NRC staff to reach a conclusion on these matters and on the acceptability of a permanent H* amendment. However, for reasons discussed in the NRC staff's safety evaluation in Reference 11, the NRC staff concluded that there was an adequate technical basis to support issuance of an interim H* amendment.

In Reference 13, the NRC staff documented a list of questions that would need to be addressed satisfactorily before the NRC staff would be able to approve a permanent H* amendment. These questions related to the technical justification for the eccentricity adjustment, the distribution of contact pressure around the tube circumference, and a new model under development by Westinghouse to address the aforementioned issue encountered with the Model D5 SGs.

On June 14 and 15, 2010, the NRC staff conducted an audit at the Westinghouse Waltz Mill Site (Reference 14). The purpose of the audit was to gain a better understanding of the H* analysis pertaining to eccentricity, to review draft responses to the NRC staff's questions in Reference 13, and to determine which documents would need to be provided on the docket to support any future requests for a permanent H* amendment. Based on the audit, including review of pertinent draft responses to Reference 13, the NRC staff concluded that eccentricity did not appear to be a significant variable affecting either average T/TS contact pressure at a given elevation or calculated values of H*. The NRC staff found that average contact pressure at a given elevation is primarily a function of the average bore diameter change at that elevation associated with the pressure and temperature loading of the tubesheet. Accordingly, the NRC staff concluded that no adjustment of computed average bore diameter change considered in the thick shell model is needed to account for eccentricities computed by the 3-D FEA. The material reviewed during the audit revealed that computed H* values from the reference analyses continued to be conservative when the eccentricity adjustment factor is not applied.

During the audit, Westinghouse presented preliminary details of a new T/TS interaction model developed as an alternative to the thick shell interaction model. This model is termed the square cell model and was developed in response to the difficulty encountered when applying the eccentricity adjustment to the Model D5 SG T/TS interaction analysis under MSLB conditions, using the thick shell model. Early results with this model indicated significant differences compared to the thick shell model, irrespective of whether the eccentricity adjustment was applied to the thick shell model. The square cell model revealed a fundamental problem with how the results of the 3-D FEA model of the lower SG assembly were being applied to the tubesheet bore surfaces in the thick shell model. As discussed in Section 4.2.2 above, the perforated tubesheet is modeled in the 3-D FEA model as a solid plate whose material properties were selected such that the gross stiffness of the solid plate is equivalent to that of a perforated plate, under the primary-to-secondary pressure acting across the thickness of the plate. This approach tends to smooth out the distribution of tubesheet displacements as a function of radial and circumferential location in the tubesheet, and ignores local variations of the displacements at the actual bore locations. These smoothed out displacements from the 3-D FEA results were the displacements applied to the bore surface locations in the thick shell model. The square cell model provides a means for post-processing the 3-D FEA results such as to account for localized variations of tubesheet displacement at the bore locations as part of T/TS interaction analysis. The square cell model was still under development at the time of the audit and no draft documentation of the model was available for the NRC staff's review. Although the NRC staff found that objectives of the new model approach appeared reasonable, the NRC staff was unable to provide feedback on the details of the approach at that time. The NRC staff also observed (Reference 14) that the square cell model approach might need to be applied to the Model F, 44F, and 51F SGs to confirm that the analyses for these plants were conservative.

4.2.3.2 Square Cell Model

Documentation for the square cell model is included with the subject amendment request for an interim H* at Surry Unit 2. The square cell model is a 2-D, plane stress, finite element model of a single square cell of the tubesheet with a bore hole in the middle and each of the four sides of the cell measuring one tube pitch in length. Displacement boundary conditions are applied at the edges of the cell, based on the displacement data from the 3-D FEA model. The model also includes the tube cross-section inside the bore. Displacement compatibility between the tube outer surface and bore inner surface is enforced, except at locations where a gap between the tube and bore tries to occur.

The square cell model is applied to nine different elevations, from the top to the bottom of the tubesheet, for each tube and loading case analyzed. The square cell slices at each elevation are modeled to act independently of one another. Tube-to-tubesheet contact pressure results from each of the nine slices are used to define the contact pressure distribution from the top to the bottom of the tubesheet.

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.

The square cell model assumes as an initial condition that each tube outer surface is in contact with the inner surface of the tubesheet bore, at room temperature and atmospheric pressure, with zero RCP associated with the hydraulic expansion process. The NRC staff finds the assumption of zero RCP in all tubes to be a conservative assumption.

The limiting tube locations in terms of H* were determined during the reference analysis to lie along the plane of symmetry perpendicular to the divider plate. The outer edges of the square cell model conform to the revised mesh pattern along this plane of symmetry in the 3-D FEA model of the lower SG assembly, as discussed in Section 4.2.2. Because the tubesheet bore holes were not explicitly modeled in the 3-D FEA, only the average displacements along each side of the square cell are known from the 3-D FEA. Three different assumptions for applying displacement boundary conditions to the edges of the square cell model were considered, to allow for a range of possibilities about how local displacements might vary along the length of each side. The most conservative assumption, in terms of maximizing the calculated H* distance, was to apply the average transverse displacement uniformly over the length of each edge of the square cell.

Primary pressure acting on the inside tube surface, and crevice pressure[1] acting on both the tube outside surface and tubesheet bore surface, are not modeled directly as in the case of the thick shell model. Instead, the primary side (inside) of the tube is assumed to have a pressure equal to the primary pressure minus the crevice pressure. Note the crevice pressure varies as a function of the elevation being analyzed, as discussed in Section 4.2.4.

The NRC staff has not completed its review of the square cell model. This review will need to be completed before the NRC staff can approve any request for a permanent H* amendment. However, for reasons discussed in Section 4.5, the NRC staff concludes the proposed H* distances will ensure for at least one operating cycle (one fuel 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, without undue risk to public health and safety.

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 4.2.4 for more information.

4.2.4 Crevice Pressure Evaluation

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 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. The NRC staff finds that this approach acceptably addresses the NRC staff's concerns cited in Reference 4 concerning the use of the limiting median crevice pressure value of the normal operating and MSLB data, respectively, for each axial slice, in previous H* analyses in support of amendment applications submitted prior to 2008. The NRC staff finds the crevice pressure distributions used to support the current amendment request to be more realistic and more conservative than those used previously.

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.

4.2.5 H* Calculation Process

The calculation of H* consists of the following steps for each loading case considered:

1. Perform initial H* estimate (mean H* estimate) using the T/TS 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 contact pressure distribution over the length of the T/TS crevice. This initial estimate did not

consider the effect of the Poison's contraction of the tube radius associated with application of the axial end cap load (see step 6 below).

2. In the reference analysis (Reference 12), a 0.3-inch adjustment was added 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. This adjustment is not included in the revised H* analysis of the subject amendment request, as discussed and evaluated in Section 4.2.5.1 of this SE.

3. Unlike Model F and D5 SGs, the analysis for the Model 51F SGs did not require an adjustment to correct for the actual temperature distribution in the tubesheet, because the temperature distribution was included directly in the original analysis (Reference 12). This step is discussed and evaluated in Section 4.2.2 of this SE.

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. The NRC staff's evaluation of the probabilistic analysis is provided in Sections 4.2.6 and 4.2.7 of this SE.

5. Add a crevice pressure adjustment to the probabilistic estimate of H* to account for the crevice pressure distribution that results from the tube being severed at the final H* value, rather than at the bottom of the tubesheet. This step is discussed and evaluated in Section 4.2.5.2 of this SE.

6. This step has been added to the H* calculation process since the reference analysis to support the subject interim amendment request. This step involves adding an additional adjustment to the probabilistic estimate of H* to account for the Poisson contraction of the tube radius due to the axial end cap load acting on each tube. This step is discussed and evaluated in Section 4.2.5.3 of this SE.

4.2.5.1 BET Considerations

In the reference H* analysis (Reference 12), a 0.3-inch adjustment was added to the initial H* estimate to account for uncertainty in the BET location, relative to the top of the tubesheet, based on a BET uncertainty analysis for Model F SGs conducted by Westinghouse. As discussed previously in Section 4.2.3.1, the reference analysis was based on the thick shell model and the results of that analysis did not indicate a loss of contact pressure at the TTS during Normal Operating Pressure (NOP) or Steam Line Break (SLB) conditions; therefore, this adjustment for the BET location was necessary. In response to NRC staff's questions regarding the BET uncertainty analysis, Westinghouse performed an analysis (Reference 15) that showed BET locations as great as one inch below the TTS could be tolerated at any tube location. Because the limiting calculated H* value is in the most-limiting tubesheet sector, that H* value provides greater than one inch of margin for most other tubesheet sectors. For those few sectors in the tubesheet where the local H* distance was within one inch of the maximum H* distance, Westinghouse showed that the contact pressure gradient was positive with increasing depth into the tubesheet, and therefore, an H* length reduced by one inch still met the pull out resistance requirements, including appropriate safety factors.

The new analysis performed in Reference 16 has made the need for this adjustment moot, as the square cell model shows a loss of contact pressure at the TTS that is greater than the possible variation in the BET location. The loss of contact pressure at the TTS shown in the square cell model (which is unrelated to BET location) is compensated for by a steeper contact pressure gradient than was shown previously in the thick shell model H* analysis.

4.2.5.2 Crevice Pressure Adjustment

As discussed in Section 4.2.5, steps 1 through 4 of the H* calculation process leading to a probabilistic H* estimate are performed with the assumption that the tube is severed at the bottom of the tubesheet for purposes of calculating the distribution of crevice pressure as a function of elevation. If the tube is assumed to be severed at the initially computed H* distance and steps 1 through 4 repeated, a new H* may be calculated, which will be incrementally larger than the first estimate. This process may be repeated until the change in H* becomes small (convergence). Sensitivity analyses conducted during the reference analysis with the thick shell model showed that the delta between the initial H* estimate and final (converged) estimate is a function of the initial estimate for the tube in question. This delta (i.e., the crevice pressure adjustment referred to in step 5 of Section 4.2.5) was plotted as a function of the initial H* estimate for the limiting loading case and tube radial location. The NRC staff concludes this to be an acceptable approach where the H* estimates are based on the thick shell model; however, the NRC staff has not yet reached a conclusion regarding the applicability of this adjustment to H* estimates that are based on the square cell model. The NRC staff will need to reach a conclusion on this point before the NRC staff can approve any request for a permanent H* amendment. However, for reasons discussed in Section 4.5, the NRC staff concludes the proposed H* distances will ensure for at least one operating cycle (one fuel 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, without undue risk to public health and safety.

4.2.5.3 Poisson Contraction Effect

The axial end cap load acting on each tube is equal to the primary-to-secondary pressure difference times the tube cross-sectional area. For purposes of resisting tube pullout under normal and accident conditions, the end cap loads used in the H* analyses are based on the tubesheet bore diameter, which the NRC staff finds to be a conservative assumption. The axial end cap load tends to stretch the tube in the axial direction, but causes a slight contraction in the tube radius due to the Poisson's Ratio effect. This effect, by itself, tends to reduce the T/TS contact pressure and, thus, to increase the H* distance. The axial end cap force is resisted by the axial friction force developed at the T/TS joint. Thus, the axial end cap force begins to decrease with increasing distance into the tubesheet, reaching zero at a location before the H* distance is reached. This is because the H* distances are intended to resist pullout under the end cap loads with the appropriate factors of safety applied as discussed in Section 4.2.1.

This Poisson radial contraction effect was neglected in the reference analyses, but is accounted for in the analyses supporting the subject amendment request. A simplified approach was followed. First, thick shell equations were used to estimate the reduction in contact pressure associated with application of the full end cap load, assuming none of this end cap load has been reacted by the tubesheet. The T/TS contact pressure distributions determined in Step 4 of the H* calculation process in Section 4.2.5 were reduced by this amount. Second, the friction force associated with these reduced T/TS contact pressures were integrated with distance into the tubesheet, and the length of engagement necessary to react one times the end cap loading (i.e., no safety factor applied) was determined. At this distance (termed attenuation distance by Westinghouse), the entire end cap loading was assumed to have been reacted by the tubesheet, and the axial load in the tube below the attenuation distance was assumed to be zero. Thus, the T/TS contact pressures below the attenuation distance were assumed to be unaffected by the Poisson radial contraction effect. Finally, a revised H* distance was calculated, where the T/TS contact pressures from Step 4 of Section 4.2.5 were reduced only over the attenuation distance. The NRC staff has not completed its review of the applied adjustment to account for the Poisson radial contraction effect. However, for reasons discussed in Section 4.5, the NRC staff concludes the proposed H* distances will ensure for at least one operating cycle (one fuel 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, without undue risk to public health and safety.

4.2.6 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 of this SE, assuming all tubes to be completely severed at their H* distance. The NRC staff finds this probabilistic acceptance standard is consistent with what the NRC 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 17) employs a consistent criterion. The NRC 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 previously considered in probabilistic risk assessments (References 18 and 19).

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 NRC staff has been encouraging the industry to revise its guidelines to call for calculating such probabilities at a 95-percent confidence level when performing operational assessments and a 50-percent confidence level when performing condition monitoring (Reference 20). In the meantime, the calculated H* distances supporting the interim amendment currently being requested have been evaluated at the 95-percent confidence level, as recommended by the NRC staff.

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 that experiences a large increase in the primary-to-secondary pressure differential. However, normal operating conditions were found to be the most-limiting conditions, in terms of meeting the tube pullout margins in Section 4.2.1. 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 NRC staff and industry on which population needs to be considered in the probabilistic analysis for normal operating conditions, the calculated H* distances for the Model 51F SGs in the subject amendment request are 0.95-probability/95- percent confidence estimates based on the entire tube population for the plant, which is consistent with the NRC staff's recommendation.

Based on the above, the NRC staff concludes that the proposed H* distance in the subject license amendment request is based on acceptable probabilistic acceptance standards evaluated at acceptable confidence levels.

4.2.7 Probabilistic Analyses

Sensitivity studies were conducted during the reference analyses (Reference 12) and demonstrated that H* was highly sensitive to the potential variability of the coefficients of thermal expansion (CTE) for the Alloy 600TT tubing material and the SA-508 Class 2a tubesheet material. Given that no credit was taken in the reference H* analyses (Reference 12) 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 during 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 4.2.5), 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 in the reference analyses (Reference 12). 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 of the reference analyses relied 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 analyses (Reference 12) and questioned whether the H* influence curves had been conservatively treated. To address this concern, the licensee submitted new H* analyses as documented in Reference 9. These analyses made direct use of the H* influence curves in a manner the NRC staff finds to be acceptable.

The revised reference analyses in Reference 9 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 initial value of H* (based on nominal values of material and geometric input parameters) 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 revised reference analyses also addressed a question posed by the NRC staff in Reference 4 concerning the appropriate way to sample material properties for the tubesheet, whose properties are

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

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 for a single SG tube population or all SG population, as appropriate. The NRC staff concludes that this approach addresses the NRC's question in a realistic fashion and is acceptable.

In the reference H* analyses (References 12 and 9) Monte Carlo analyses, based on the thick shell T/TS interaction model, were used to evaluate the statistical variability of H*, due to the CTE variability of the tube and tubesheet materials. New Monte Carlo analyses, based on the square cell model results, were not performed in support of the subject interim amendments. Instead, the probabilistic analysis utilized the results of the Monte Carlo analyses from References 12 and 9 to identify CTE values for the tube and tubesheet associated with the probabilistic H* values near the desired rank ordering. Tube CTE values associated with the high ranking order estimates are generally negative variations from the mean value, whereas tubesheet CTE values associated with the high ranking order estimates are generally positive variations from the mean value. For the upper 10 percent of the Monte Carlo results ranking order, a combined uncertainty parameter, "alpha," was defined as the square root of the sum of the squares of the associated tube and tubesheet CTE values for each Monte Carlo sample. Alpha was plotted as a function of the corresponding H* estimate and separately as a function of rank order. Each of these plots exhibited well defined "break lines," representing the locus of maximum H* estimates and maximum rank orders associated with a given values of alpha. From these plots, paired sets of tube and tubesheet CTE values were selected such as to maximize the H* estimate and to upper and lower bound the rank orders corresponding to the appropriate probabilistic acceptance criteria described and evaluated in Section 4.2.6. These CTE values were then input to the lower SG assembly 3-D finite element model and the square cell model to yield probabilistic H* estimates. These H* estimates were then plotted as a function of rank ordering, allowing the interpolation of H* values at the desired rank orders.

The limiting probabilistic H* value, evaluated at the appropriate acceptance standard as discussed in Section 4.2.6 and with the adjustments for crevice pressure and Poisson radial contraction effect discussed in Section 4.2.5, is bounded by the proposed H* value of 17.74 inches in the subject request for an interim amendment.

The NRC staff has not completed its evaluation of the above probabilistic analysis, which must be done before the NRC staff can approve any request for a permanent H* amendment. However, for reasons discussed in Section 4.5, the NRC staff concludes the proposed H* distances will ensure for at least one operating cycle (one fuel 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, without undue risk to public health and safety.

4.2.8 Coefficient of Thermal Expansion

During operation, a large part of contact pressure in a SG T/TS joint is derived from the difference in the CTE between the tube and tubesheet. As discussed in Section 4.2.7, 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 4, 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 (Appendix A to Reference 12). 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 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 respond to the concerns stated in Reference 4 and are acceptable.

4.3 Accident-induced Leakage Considerations

Operational leakage integrity is assured by monitoring primary-to-secondary leakage relative to the applicable TS LCO limits in TS 3.1.C, "RCS Operational LEAKAGE." However, it must also be demonstrated that the proposed TS changes do not create the potential for leakage during DBA to exceed the accident-leakage performance criteria in TS 6.4.Q.2.b, 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, 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 T/TS 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 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, 2.03, meaning that it is the transient expected to result in the largest increase in leakage relative to normal operating conditions.

As a condition of NRC approval of Amendment No. 266 (i.e., the currently approved alternate repair criteria (Reference 11)) for Surry Unit 2, the licensee provided a commitment that described how the leakage factor would be used to satisfy TS 6.4.Q.1 for condition monitoring and TS 6.4.Q.2.b regarding performance criteria for accident induced leakage:

> For the Condition Monitoring assessment, the component of operational leakage from the prior cycle from below the H* distance will be multiplied by a factor of 2.03 and added to the total accident leakage from any other source and compared to the allowable accident induced leakage limit. For the Operational Assessment, the difference between the allowable accident induced leakage and the accident induced leakage from sources other than the tubesheet expansion region will be divided by 2.03 and compared to the observed operational leakage. An administrative operational limit will be established to not exceed the calculated value.

In the subject amendment request (Reference 1), the licensee stated the commitments previously made in accordance with Amendment No. 266 were completed and that the commitments regarding Condition Monitoring/Operational Assessment and tube slippage would remain in place and will also apply to the subject license amendment. Because the other commitments in Amendment No. 266 were one-time actions (i.e., tube plugging and verification of tube expansion location) these commitments would not need to be repeated in this amendment request. The NRC staff finds that continuing the commitments regarding Condition Monitoring/Operational Assessment and tube slippage acceptable, since they provide 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 NRC staff also concurs with not repeating the previous one-time commitments.

4.4 Proposed Change to TS 6.6.A.3, "Steam Generator Tube Inspection Report"

The NRC staff has reviewed the proposed reporting requirements and finds that they are sufficient to allow the NRC staff to monitor the implementation of the proposed amendment. Based on this conclusion, the NRC staff finds that the proposed reporting requirements are acceptable.

4.5 Technical Bases for Interim H* Amendment

The proposed H* value is based on the conservative assumption that all tubes in all steam generators 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 steam generators, 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 Sections 4.2.3.2, 4.2.5.2, 4.2.5.3, and 4.2.7, the NRC staff has not completed its review of certain elements of the technical basis for the proposed H* distance. Thus, in spite of the significant conservatisms embodied in the proposed H* distance, the NRC 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 steam generators, assuming all tubes to be severed at the H* location. The NRC staff will need to complete its review of these certain elements before it can approve any request for a permanent H* amendment. However, for the reasons below, the NRC staff concludes the proposed H* distances will ensure for at least one operating cycle (one fuel 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, without undue risk to public health and safety.

From a fleet-wide perspective (for all Westinghouse plants with Alloy 600TT tubes), 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 one 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 NRC staff's judgment based on experience that it will continue to be limited to a small percentage of tubes, mostly near the tube ends, over the next operating cycle (approximately 18 months for Surry Unit 2). The NRC staff's observations are based on the review of SG tube inspection reports from throughout the PWR fleet. These reports are reviewed and the NRC staff's conclusions are typically documented within a year of each SG tube inspection. Reference 21 provides an example of such a review for Surry Unit 2 by the NRC staff.

At Surry Unit 2, the most recent inspection of tubing below the current H* distance of 16.95 inches was performed in the spring of 2008. The licensee reported in Reference 22 that the bottom four inches of the hot-leg tube ends were inspected in 100 percent of all three SGs. The inspection results showed axial and circumferential indications suggestive of inside diameter flaws within 0.2 inches of the tube end, in all three SGs. Steam Generator A had 60 tubes with 60 indications, SG B had 37 tubes with 39 indications, and SG C had 20 tubes with 21 indications. Additionally, full tubesheet depth, rotating probe examinations were performed in a small number of cold-leg tubes. Twelve tubes in SG B and 22 tubes in SG C were examined and the results indicated no degradation. The licensee did not report any other corrosion-related degradation mechanisms.

Reference 23 documents the most recent inspections the licensee performed in the fall of 2009. The licensee performed bobbin coil examinations of 100 percent of the tubes in SG A (except for the u-bends in rows 1 and 2) and the only forms of degradation noted were anti-vibration bar wear, foreign object wear, and tube support wear. The licensee performed rotating probe examinations within the tubesheet region as discussed in Reference 23. These examinations focused on the upper regions of the tubesheet since the NRC staff had approved, in Reference 11, an interim H* amendment for RFO 22 and the subsequent operating cycle (one fuel cycle). No corrosion-related degradation was observed. The NRC staff finds the extent and severity of cracking at Surry Unit 2 to be limited and 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 NRC staff also concludes there is reasonable assurance during the next operating 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 NRC 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 4.3 will remain conservative even should there be a loss of T/TS contact near the top of the tubesheet due to tubesheet bore eccentricity effects.

4.6 Conclusion

The proposed license amendment applies only to RFO 23 and the subsequent operating cycle for Surry Unit 2. The NRC staff concludes that there is sufficient conservatism embodied in the proposed H* distances to ensure for at least one operating cycle (one fuel 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, without undue risk to public health and safety. Based on this finding, the NRC staff further concludes that the proposed amendment is acceptable.

5.0 FINAL NO SIGNIFICANT HAZARDS CONSIDERATION DETERMINATION

The regulations at 10 CFR 50.92 state that the Commission may make a final determination that a license amendment involves no significant hazards considerations, if operation of the facility in accordance with the proposed amendment would not (1) involve a significant increase in the probability or consequences of an accident previously evaluated, (2) create the possibility of a new or different kind of accident from any accident previously evaluated, or (3) involve a significant reduction in a margin of safety.

These amendments have been evaluated against the standards in 10 CFR 50.92 as discussed below:

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   No, the previously analyzed accidents are initiated by the failure of plant structures, systems, or components. The proposed change that alters the steam generator inspection/repair criteria and the steam generator inspection reporting criteria does not have a detrimental impact on the integrity of any plant structure, system, or component that initiates an analyzed event. The change will not alter the operation of, or otherwise increase the failure probability of any plant equipment that initiates an analyzed accident. Of the applicable accidents previously evaluated, the limiting transients with consideration to the change to the steam generator tube inspection and repair criteria are the steam generator tube rupture (SGTR) event and the steam line break (SLB) postulated accidents. During the SGTR event, the required structural integrity margins of the steam generator tubes and the tube-to-tubesheet joint over the H* distance will be maintained. Tube rupture in tubes with cracks within the tubesheet is precluded by the constraint provided by the tube-to-tubesheet joint. This constraint results from the hydraulic expansion process, thermal expansion mismatch between the tube and tubesheet, and from the differential pressure between the primary and secondary side. Based on this design, the structural margins against burst, as discussed in Regulatory Guide (RG) 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes," are maintained for both normal and postulated accident conditions.

The change has no impact on the structural or leakage integrity of the portion of the tube outside of the tubesheet. The change maintains structural integrity of the steam generator tubes and does not affect other systems, structures, components, or operational features. Therefore, the change results in no significant increase in the probability of the occurrence of a SGTR or previously evaluated accident.

At normal operating pressures, leakage from primary water stress corrosion cracking below the proposed limited inspection depth is limited by both the tube-to tubesheet crevice and the limited crack opening permitted by the tubesheet constraint. Consequently, negligible normal operating leakage is expected from cracks within the tubesheet region. The consequences of an SGTR event are affected by the primary to secondary leakage flow during the event. However,
primary to secondary leakage flow through a postulated broken tube is not affected by the changes since the tubesheet enhances the tube integrity in the region of the hydraulic expansion by precluding tube deformation beyond its initial hydraulically expanded outside diameter. Therefore, the changes do not result in a significant increase in the consequences of a SGTR.

The consequences of a steam line break (SLB) are also not significantly affected by the changes. During a SLB accident, the reduction in pressure above the tubesheet on the shell side of the steam generator creates an axially uniformly distributed load on the tubesheet due to the reactor coolant system pressure on the underside of the tubesheet. The resulting bending action constrains the tubes in the tubesheet thereby restricting primary to secondary leakage below the midplane.

Primary to secondary leakage from tube degradation in the tubesheet area during the limiting accident (i.e., a SLB) is limited by flow restrictions. These restrictions result from the crack and tube-to-tubesheet contact pressures that provide a restricted leakage path above the indications and also limit the degree of potential crack face opening as compared to free span indications.

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

The leakage factor of 2.03 is a bounding value for all SGs, both hot and cold legs, in Table 9-7 of WCAP-17092-P. Also as shown in Table 9-7 of WCAP-17092-P, for Surry for a postulated SLB, a leakage factor of 1.80 has been calculated. However, for Surry, a more conservative leakage factor of 2.03 will be applied to the normal operating leakage associated with the tubesheet expansion region in the condition monitoring (CM) assessment and the operational assessment (OA). Specifically, for the CM assessment, the component of leakage from the prior cycle from below the H* distance will be multiplied by a factor of 2.03 and added to the total leakage from any other source and compared to the allowable accident induced leakage limit. For the OA, the difference in the leakage between the allowable leakage and the accident induced leakage from sources other than the tubesheet expansion region will be divided by the leakage factor of 2.03 and compared to the observed operational leakage.

Therefore, the change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   No, the change that alters the steam generator inspection/repair criteria and the steam generator inspection reporting criteria does not introduce any new equipment, create new failure modes for existing equipment, or create any new limiting single failures. Plant operation will not be altered, and all safety functions will continue to perform as previously assumed in accident analyses.

   Therefore, the change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the change involve a significant reduction in a margin of safety?

   No, the change that alters the steam generator inspection/repair criteria and the steam generator inspection reporting criteria maintains the required structural margins of the steam generator tubes for both normal and accident conditions. NEI 97-06, Revision 2, "Steam Generator Program Guidelines," and RG 1.121 are used as the bases in the development of the limited tubesheet inspection, depth methodology for determining that steam generator tube integrity considerations are maintained within acceptable limits. RG 1.121 describes a method acceptable to the NRC for meeting GDC 14, "Reactor Coolant Pressure Boundary," GDC 15, "Reactor Coolant System Design," GDC 31, "Fracture Prevention of Reactor Coolant Pressure Boundary," and GDC 32, "Inspection of Reactor Coolant Pressure Boundary," by reducing the Probability and consequences of a SGTR. RG 1.121 concludes that by determining the limiting safe conditions for tube wall degradation the probability and consequences of a SGTR are reduced. This RG uses safety factors on loads for tube burst that are consistent with the requirements of Section III of the ASME Code

   For axially oriented cracking located within the tubesheet, tube burst is precluded due to the presence of the tubesheet. For circumferentially oriented cracking, the H* analysis, documented in Section 4 of the license amendment request, defines a length of degradation free expanded tubing that provides the necessary resistance to tube pullout due to the pressure induced forces, with applicable safety factors applied. Application of the limited hot and cold leg Tubesheet inspection criteria will preclude unacceptable primary to secondary leakage during all plant conditions. The methodology for determining leakage provides for large margins between calculated and actual leakage values in the proposed limited tubesheet inspection depth criteria.

Based on this review, the Commission has made a final determination that these amendments involve no significant hazard consideration.

6.0 STATE CONSULTATION

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

7.0 ENVIRONMENTAL CONSIDERATION

The amendments change requirements 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 amendments involve 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 made a final finding that the amendments involve no significant hazards consideration. The amendments also relate to changes in recordkeeping, reporting, or administrative procedures or requirements. Accordingly, the amendments meet the eligibility criteria for categorical exclusions set forth in 10 CFR 51.22(c)(9) and (c)(10). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendments.

8.0 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 amendments will not be inimical to the common defense and security or to the health and safety of the public.

9.0 REFERENCES

1. Virginia Electric and Power Company (VEPCO), Letter 10-715, to NRC, "Virginia Electric and Power Company (Dominion) Surry Power Station, Unit 2 Proposed Technical Specification Change Temporary Alternate Repair Criteria for Steam Generator Tube Repair for Unit 2," dated December 16, 2010, NRC ADAMS Accession No. ML103550206. This letter also transmitted Reference 16.

2. Wolf Creek Nuclear Operating Corporation, Letter ET-06-0004, to NRC, "Docket No. 50-482: Revision to Technical Specification 5.5.9, 'Steam Generator Tube Surveillance Program,'" dated February 21, 2006, NRC ADAMS Accession No. ML060600456.

3. Wolf Creek Nuclear Operating Corporation, Letter ET-08-0010, to NRC, "Docket No. 50-482: Withdrawal of License Amendment Request for a Permanent Alternate Repair Criteria in Technical Specification (TS) 5.5.9, 'Steam Generator (SG) Program,'" dated February 14, 2008, NRC ADAMS Accession No. ML080580201.

4. NRC Letter to Wolf Creek Nuclear Operating Corporation, "Wolf Creek Generating Station – Withdrawal of License Amendment Request on Steam Generator tube Inspections (TAC NO. MD0197)," February 28, 2008, NRC ADAMS Accession No. ML080450185.

5. NRC Meeting Minutes, Memorandum to A. Hiser, NRC, from A. Johnson, NRC, "Summary of the October 29 and 30, 2008, Category 2 Public Meeting with the Nuclear Energy Institute (NEI) and Industry to Discuss Modeling Issues Pertaining to the Steam Generator Tube-to-tubesheet Joints," dated November 24, 2008, NRC ADAMS Accession No. ML083300422.

6. NRC Meeting Minutes, Memorandum to A. Hiser, NRC, from A. Johnson, NRC, "Summary of the January 9, 2009, Category 2 Public Meeting with the U.S. Nuclear Industry Representatives to Discuss Steam Generator H*/B* Issues," dated February 6, 2009, NRC ADAMS Accession No. ML090370945.

7. NRC Meeting Minutes, Memorandum to M. Gavrilas, NRC, from A. Johnson, NRC, "Summary of the April 3, 2009, Category 2 Public Meeting with U.S. Nuclear Industry Representatives to Discuss Steam Generator H* Issues," dated May 1, 2009, NRC ADAMS Accession No. ML091210437.

8. VEPCO Letter 09-455, to NRC, "Surry Power Station Units 1 and 2 Proposed License Amendment Request Permanent Alternate Repair Criteria for Steam Generator Tube Repair for Units 1 and 2," dated July 28, 2009, NRC ADAMS Accession No. ML092150464. This letter also transmitted Reference 12.

9. VEPCO Letter 09-455A, to NRC, dated September 16, 2009, responding to NRC's Surry Power Station Unit 1 and 2 RAIs, "Surry Power Station Units 1 and 2 Response to Request for Additional Information Proposed License Amendment Request Permanent Alternate Repair Criteria (PARC) for Steam Generator Tube Repair for Units 1 and 2," NRC ADAMS Accession No. ML092660615. This letter also transmitted Westinghouse Electric Company LLC (WEC) Letter CAW-09-2669, dated August 31, 2009, "Subject:

LTR-SGMP-09-108 P-Attachment, 'Response to NRC Request for Additional Information on H*; Model 44F and 51F Steam Generators,' dated August 2009 (Proprietary)," and NP Attachment 3, "WEC LLC LTR-SGMP-09-108 NP-Attachment, 'Response to NRC Request for Additional Information – on H*, Model 44F and Model 51F Steam Generators' (Non-Proprietary)," NRC ADAMS Accession No. ML092660616. The September 16, 2009, letter also contained, "Attachment 3 - Corrected pages for WCAP-17092-NP (Non-proprietary)," Rev. 0, June 2009, NRC ADAMS No. ML092660617. WCAP-17092-NP is Reference 12.

10. VEPCO Letter 09-455B, to NRC, September 30, 2009, "Proposed License Amendment Request One-time Alternate Repair Criteria for Steam Generator Tube Inspection/Repair for Units 1 and 2," amending its H* application to be a one-time change, dated September 30, 2009, NRC ADAMS Accession No. ML092800358.

11. NRC Letter to VEPCO, "Surry Power Station, Unit Nos. 1 and 2, Issuance of Amendments Regarding License Amendment Request for Alternate Repair Criteria for Steam Generator Tubesheet Expansion Region (TAC Nos. ME1783 and ME1784)," dated November 5, 2009, NRC ADAMS Accession No. ML092960484.

12. WEC Report, WCAP-17092-NP, Revision 0, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model 51F)," (Non-Proprietary) June 2009, NRC ADAMS Accession No. ML092150462.

13. NRC Letter to Southern Nuclear Operating Company, "Vogtle Electric Generating Plant, Units 1 and 2 - Transmittal of Unresolved Issues Regarding Permanent Alternate Repair Criteria for Steam Generators," dated November 23, 2009, NRC ADAMS Accession No. ML093030490.

14. NRC memorandum, R. Taylor to G. Kulesa, "Vogtle Electric Generating Plant – Audit of Steam Generator H* Amendment Reference Documents," July 9, 2010, NRC ADAMS Accession No. ML101900227.

15. WEC Letter LTR-NRC-10-69, "Subject: Submittal of LTR-SGMP-09-111 P-Attachment, Rev. 1 and LTR-SGMP-09-111 NP-Attachment, Rev. 1, 'Acceptable Value of the Location of the Bottom of the Expansion Transition (BET) for Implementation of H*,' (Proprietary/Non-Proprietary) for Review and Approval," NRC ADAMS Accession Nos. ML103400083 (Letter and Non-Proprietary) and ML103400084 (Proprietary).

16. WEC Report, WCAP-17345-NP, Rev. 0, "H*: Resolution of NRC Technical Issue Regarding Tubesheet Bore Eccentricity (Model 44F 3-Loop and Model 51F)," (Non-Proprietary) - November 2010, NRC ADAMS Accession No. ML110240266.

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

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

19. NUREG-1570, "Risk Assessment of Severe Accident-Induced Steam Generator Tube Rupture," March 1998, NRC ADAMS Accession No. ML070570094.

20. NRC Meeting Minutes, Memorandum to A. Hiser, NRC, from A. Johnson, NRC, "Summary of the January 8, 2009, Category 2 Public Meeting with the Nuclear Energy Institute (NEI) and Industry to Discuss Steam Generator Issues," dated February 6, 2009, NRC ADAMS Accession No. ML090370782.

21. NRC Letter to VEPCO, "Surry Power Station, Unit No. 2 – Review of the 2008 Steam Generator Inservice Inspection Report (TAC No. ME0165)," dated November 23, 2009, NRC ADAMS Accession No. ML092940238.

22. VEPCO Letter 08-0687, to NRC, "Virginia Electric and Power Company Surry Power Station Unit 2, Steam Generator Tube Inservice Inspection Report for the 2008 Refueling Outage," dated November 14, 2008, NRC ADAMS Accession No. ML090060111.

23. VEPCO Letter 10-220, to NRC, "Virginia Electric and Power Company Surry Power Station Unit 2 Steam Generator Tube Inservice Inspection Report for the 2009 Refueling Outage," dated May 24, 2010, NRC ADAMS Accession No. ML101530533.

Principal Contributor: Andrew B. Johnson, NRR/DCI

Date: May 20, 2011

A copy of the Safety Evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

/RA/ by JWiebe for

Karen Cotton, Project Manager
Plant Licensing Branch II-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-281

Enclosures:
1. Amendment No. 273 to DPR-37
2. Safety Evaluation

cc w/encls: Distribution via Listserv

DISTRIBUTION:
Public LPL2-1 R/F
RidsOgcRp Resource
RidAcrsAcnw_MailCTR Resource
RidsNrrDciCsgb Resource
RidsNrrLAMO'Brien Resource
RidsRgn2MailCenter Resource
RidsNrrDorlDpr Resource
RTaylor, NRR
RidsNrrDirsItsb Resource
RidsNrrDorlLpl2-1Resourc
RidsNrrPMSurry Resourc
AJohnson, NRR

ADAMS Accession No. ML11090A000 *SE transmitted by memo dated 3/23/11

OFFICE	NRR/LPL2-1/PM	NRR/LPL2-1/LA	NRR/DCI/CSGB/BC	OGC NLO	NRR/LPL2-1/BC	NRR/LPL2-1/PM
NAME	KCotton	MO'Brien	RTaylor * (KKarwoski for)	DRoth	GKulesa	KCotton (JWiebe for)
DATE	5/16/11	5/16/11	03/23/11	5/18/11	5/20/11	5/20/11

OFFICIAL RECORD COPY