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

November 5, 2009

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 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)

Dear Mr. Heacock:

The U.S. Nuclear Regulatory Commission has issued the enclosed Amendment No. 267 to Renewed Facility Operating License No. DPR-32 and Amendment No. 266 to Renewed Facility Operating License No. DPR-37 for the Surry Power Station (Surry), Unit Nos. 1 and 2, respectively. The amendments change the Technical Specifications (TSs) in response to your application dated July 28, 2009 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML092150464), supplemented by letters dated September 16 and 30, 2009 (ADAMS Accession Nos. ML092660615 and ML092800358).

These amendments revise the TS of Surry, Units 1 and 2. The request proposed changes to the inspection scope and repair requirements of TS Section 6.4.Q, "Steam Generator (SG) Program," to the reporting requirements of TS Section 6.6.A.3, "Steam Generator (SG) Tube Inspection Report," and to TS Sections 4.13 and 3.1.C, "RCS [Reactor Coolant System] Operational Leakage." The proposed changes would establish alternate repair inspection and criteria for portions of the SG tubes within the tubesheet. The alternate inspection and repair criteria would be applicable to Unit 1 during Refueling Outage 23 (fall 2010) and the subsequent operating cycle, and to Unit 2 during Refueling Outage 22 (fall 2009) and the subsequent operating cycle.

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,

Karen Cotton

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

Docket Nos. 50-280 and 50-281

Enclosures:
1. Amendment No. 267 to DPR-32
2. Amendment No. 266 to DPR-37
3. Safety Evaluation

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
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VIRGINIA ELECTRIC AND POWER COMPANY

DOCKET NO. 50-280

SURRY POWER STATION, UNIT NO. 1

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 267
Renewed License No. DPR-32

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

   A. The application for amendment by Virginia Electric and Power Company (the licensee) dated July 28, 2009 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML092150464), supplemented by letters dated September 16 and 30, 2009 (ADAMS Accession Nos. ML092660615 and ML092800358, 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-32 is hereby amended to read as follows:

   (B) Technical Specifications

   The Technical Specifications contained in Appendix A, as revised through Amendment No. 267 , 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 by the end of the fall 2010 refueling outage.

FOR THE NUCLEAR REGULATORY COMMISSION

GK

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

Attachment:
Changes to License No. DPR-32
and the Technical Specifications

Date of Issuance: November 5, 2009

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. 266
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 July 28, 2009 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML092150464), supplemented by letters dated September 16 and 30, 2009 (ADAMS Accession Nos. ML092660615 and ML092800358, 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. 266 , 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 by the end of the fall 2009 refueling outage.

FOR THE NUCLEAR REGULATORY COMMISSION

G Kulesa

Gloria J. 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: November 5, 2009

ATTACHMENT

TO LICENSE AMENDMENT NO. 267

RENEWED FACILITY OPERATING LICENSE NO. DPR-32

DOCKET NO. 50-280

AND

TO LICENSE AMENDMENT NO. 266

RENEWED FACILITY OPERATING LICENSE NO. DPR-37

DOCKET NO. 50-281

Replace the following pages of the Licenses 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-32, page 3	License No. DPR-32, page 3
License No. DPR-37, page 3	License No. DPR-37, page 3
TSs	TSs
Unit 1	
TS 3.1-13	TS 3.1-13
TS 3.1-14a	TS 3.1-14a
TS 3.1-14b	TS 3.1-14b
TS 4.13-1	TS 4.13-1
TS 4.13-2	TS 4.13-2
TS 6.4-12	TS 6.4-12
TS 6.4-13	TS 6.4-13
TS 6.4-13a	--
TS 6.6-3	TS 6.6-3
TS 6.6-3a	TS 6.6-3a
TS 6.6-3b	--
Unit 2	
TS 4.13-1	TS 4.13-1
TS 6.4-12	TS 6.4-12
TS 6.4-13	TS 6.4-13
TS 6.4-13a	TS 6.4-13a
TS 6.6-3	TS 6.6-3
TS 6.6-3a	TS 6.6-3a
TS 6.6-3b	TS 6.6-3b

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 2546 megawatts (thermal).

   B. Technical Specifications

      The Technical Specifications contained in Appendix A, as revised through Amendment No. 267 are hereby incorporated in the 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 65

   F. Deleted by Amendment 71

   G. Deleted by Amendment 227

   H. Deleted by Amendment 227

   I. Fire Protection

      The licensee shall implement and maintain in effect the provisions of the approved fire protection program as described in the Updated Final Safety Analysis Report and as approved in the SER dated September 19, 1979, (and Supplements dated May 29, 1980, October 9, 1980, December 18, 1980, February 13, 1981, December 4, 1981, April 27, 1982, November 18, 1982, January 17, 1984, February 25, 1988, and

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 2546 megawatts (thermal).

B. Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 266, 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. RCS Operational LEAKAGE

Applicability

The following specifications are applicable to RCS operational LEAKAGE whenever Tavg (average RCS temperature) exceeds 200°F (200 degrees Fahrenheit).

Specifications

1. RCS operational LEAKAGE shall be limited to:

   a. No pressure boundary LEAKAGE,

   b. 1 gpm unidentified LEAKAGE,

   c. 10 gpm identified LEAKAGE, and

   d. 150 gallons per day primary to secondary LEAKAGE through any one steam generator (SG).

2.a. If RCS operational LEAKAGE is not within the limits of 3.1.C.1 for reasons other than pressure boundary LEAKAGE or primary to secondary LEAKAGE, reduce LEAKAGE to within the specified limits within 4 hours.

   b. If the LEAKAGE is not reduced to within the specified limits within 4 hours, the unit shall be brought to HOT SHUTDOWN within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

3. If RCS pressure boundary LEAKAGE exists, or primary to secondary LEAKAGE is not within the limit specified in 3.1.C.1.d, the unit shall be brought to HOT SHUTDOWN within 6 hours and COLD SHUTDOWN within the following 30 hours.

This LCO deals with protection of the reactor coolant pressure boundary (RCPB) from degradation and the core from inadequate cooling, in addition to preventing the accident analyses radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a loss of coolant accident (LOCA).

APPLICABLE SAFETY ANALYSES - Except for primary to secondary LEAKAGE, the safety analyses do not address operational LEAKAGE. However, other operational LEAKAGE is related to the safety analyses for LOCA; the amount of leakage can affect the probability of such an event. The safety analysis for an event resulting in steam discharge to the atmosphere assumes that primary to secondary LEAKAGE from all steam generators (SGs) is 1 gpm or increases to 1 gpm as a result of accident induced conditions. The LCO requirement to limit primary to secondary LEAKAGE through any one SG to less than or equal to 150 gallons per day is significantly less than the conditions assumed in the safety analysis.

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a main steam line break (MSLB) accident. Other accidents or transients involve secondary steam release to the atmosphere, such as a steam generator tube rupture (SGTR). The leakage contaminates the secondary fluid.

The UFSAR (Ref. 2) analysis for SGTR assumes the contaminated secondary fluid is released via power operated relief valves or safety valves. The source term in the primary system coolant is transported to the affected (ruptured) steam generator by the break flow. The affected steam generator discharges steam to the environment for 30 minutes until the generator is manually isolated. The 1 gpm primary to secondary LEAKAGE transports the source term to the unaffected steam generators. Releases continue through the unaffected steam generators until the Residual Heat Removal System is placed in service.

The MSLB is less limiting for site radiation releases than the SGTR. The safety analysis for the MSLB accident assumes 1 gpm total primary to secondary LEAKAGE, including 500 gpd leakage into the faulted generator. The dose consequences resulting from the MSLB and the SGTR accidents are within the limits defined in the plant licensing basis.

The RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LIMITING CONDITIONS FOR OPERATION - RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

   No pressure boundary LEAKAGE is allowed, being indicative of material deterioration. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE. Violation of this LCO could result in continued degradation of the RCPB. LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

b. Unidentified LEAKAGE

One gallon per minute (gpm) of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air monitoring and containment sump level monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB, if the LEAKAGE is from the pressure boundary.

c. Identified LEAKAGE

Up to 10 gpm of identified LEAKAGE is considered allowable because LEAKAGE is from known sources that do not interfere with detection of unidentified LEAKAGE and is well within the capability of the RCS Makeup System. Identified LEAKAGE includes LEAKAGE to the containment from specifically known and located sources, but does not include pressure boundary LEAKAGE or controlled reactor coolant pump (RCP) seal leakoff (a normal function not considered LEAKAGE). Violation of this LCO could result in continued degradation of a component or system.

d. Primary to Secondary LEAKAGE through Any One SG

The limit of 150 gallons per day per SG is based on the operational LEAKAGE performance criterion in NEI 97-06, Steam Generator Program Guidelines (Ref. 3). The Steam Generator Program operational LEAKAGE performance criterion in NEI 97-06 states, "The RCS operational primary to secondary leakage through any one SG shall be limited to 150 gallons per day." The limit is based on operating experience with SG tube degradation mechanisms that result in tube leakage. The operational leakage rate criterion in conjunction with the implementation of the Steam Generator Program is an effective measure for minimizing the frequency of steam generator tube ruptures.

APPLICABILITY - In REACTOR OPERATION conditions where T_{avg} exceeds 200°F, the potential for RCPB LEAKAGE is greatest when the RCS is pressurized.

In COLD SHUTDOWN and REFUELING SHUTDOWN, LEAKAGE limits are not required because the reactor coolant pressure is far lower, resulting in lower stresses and reduced potentials for LEAKAGE.

LCO 3.1.C.5 measures leakage through each individual pressure isolation valve (PIV) and can impact this LCO. Of the two PIVs in series in each isolated line, leakage measured through one PIV does not result in RCS LEAKAGE when the other is leaktight. If both valves leak and result in a loss of mass from the RCS, the loss must be included in the allowable identified LEAKAGE.

4.13 RCS OPERATIONAL LEAKAGE

Applicability

The following specifications are applicable to RCS operational LEAKAGE whenever T_{avg} (average RCS temperature) exceeds 200°F (200 degrees Fahrenheit).

Objective

To verify that RCS operational LEAKAGE is maintained within the allowable limits.

Specifications

A. Verify RCS operational LEAKAGE is within the limits specified in TS 3.1.C by performance of RCS water inventory balance once every 24 hours.[1, 2]

B. Verify primary to secondary LEAKAGE is ≤ 150 gallons per day through any one SG once every 72 hours. If it is not practical to assign the LEAKAGE to an individual SG, all the primary to secondary LEAKAGE should be conservatively assumed to be from one SG.

Notes:

1. Not required to be completed until 12 hours after establishment of steady state operation.
2. Not applicable to primary to secondary LEAKAGE.

BASES

SURVEILLANCE REQUIREMENTS (SR)

SR 4.13.A

Verifying RCS LEAKAGE to be within the Limiting Condition for Operation (LCO) limits ensures the integrity of the reactor coolant pressure boundary (RCPB) is maintained. Pressure boundary LEAKAGE would at first appear as unidentified LEAKAGE and can only be positively identified by inspection. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. Unidentified LEAKAGE and identified LEAKAGE are determined by performance of an RCS water inventory balance.

The RCS water inventory balance must be performed with the reactor at steady state operating conditions (stable pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows). The surveillance is modified by two notes. Note 1 states that this SR is not required to be completed until 12 hours after establishing steady state operation. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable unit conditions are established.

Steady state operation is required to perform a proper inventory balance since calculations during maneuvering are not useful. For RCS operational LEAKAGE determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the automatic systems that monitor the containment atmosphere radioactivity and the containment sump level. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. These leakage detection systems are specified in the TS 3.1.C Bases.

Note 2 states that this SR is not applicable to primary to secondary LEAKAGE because LEAKAGE of 150 gallons per day cannot be measured accurately by an RCS water inventory balance.

The 24 hour frequency is a reasonable interval to trend LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents.

SR 4.13.B

This SR verifies that primary to secondary LEAKAGE is less than or equal to 150 gallons per day through any one SG. Satisfying the primary to secondary LEAKAGE limit ensures that the operational LEAKAGE performance criterion in the Steam Generator Program is met. If this SR is not met, compliance with LCO 3.1.H, "Steam Generator Tube Integrity," should be evaluated. The 150 gallons per day limit is measured at room temperature as described in Reference 4. The operational LEAKAGE rate limit applies to LEAKAGE through any one SG.

If it is not practical to assign the LEAKAGE to an individual SG, all the primary to secondary LEAKAGE should be conservatively assumed to be from one SG. The surveillance is modified by a Note, which states that the Surveillance is not required to be performed until 12 hours after establishment of steady state operation. For RCS primary to secondary LEAKAGE determination, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

The surveillance frequency of 72 hours is a reasonable interval to trend primary to secondary LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents. The primary to secondary LEAKAGE is determined using continuous process radiation monitors or radiochemical grab sampling in accordance with the EPRl guidelines (Ref. 4).

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 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 during Refueling Outage 23 and the subsequent operating cycle, tubes with service-induced flaws located greater than 16.7 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the tubesheet to 16.7 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 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 for Refueling Outage 23 and the subsequent operating cycle, portions of the tube greater than 16.7 inches 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 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 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 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 during Refueling Outage 23 and the subsequent operating cycle, the calculated accident induced LEAKAGE rate from the portion of the tubes below 16.7 inches from the top of the tubesheet for the most limiting accident in the most limiting SG. In addition, if the calculated accident induced LEAKAGE rate from the most limiting accident is less than 2.03 times the maximum operational primary to secondary LEAKAGE rate, the report should describe how it was determined.

k. For Unit 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 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.

4.13 RCS OPERATIONAL LEAKAGE

Applicability

The following specifications are applicable to RCS operational LEAKAGE whenever T_{avg} (average RCS temperature) exceeds 200°F (200 degrees Fahrenheit).

Objective

To verify that RCS operational LEAKAGE is maintained within the allowable limits.

Specifications

A. Verify RCS operational LEAKAGE is within the limits specified in TS 3.1.C by performance of RCS water inventory balance once every 24 hours[1, 2]

B. Verify primary to secondary LEAKAGE is ≤ 150 gallons per day through any one SG once every 72 hours, with the following exception. The primary to secondary LEAKAGE for the Unit 1 B steam generator will be verified to be ≤ 20 gallons per day during Operating Cycle 23.[1] If it is not practical to assign the LEAKAGE to an individual SG, all the primary to secondary LEAKAGE should be conservatively assumed to be from one SG.

Notes:

1. Not required to be completed until 12 hours after establishment of steady state operation.
2. Not applicable to primary to secondary LEAKAGE.

BASES

SURVEILLANCE REQUIREMENTS (SR)

SR 4.13.A

Verifying RCS LEAKAGE to be within the Limiting Condition for Operation (LCO) limits ensures the integrity of the reactor coolant pressure boundary (RCPB) is maintained. Pressure boundary LEAKAGE would at first appear as unidentified LEAKAGE and can only be positively identified by inspection. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. Unidentified LEAKAGE and identified LEAKAGE are determined by performance of an RCS water inventory balance.

The RCS water inventory balance must be performed with the reactor at steady state operating conditions (stable pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows). The surveillance is modified by two notes. Note 1 states that this SR is not required to be completed until 12 hours after establishing steady state operation. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable unit conditions are established.

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 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 during Refueling Outage 23 and the subsequent operating cycle, tubes with service-induced flaws located greater than 16.7 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 16.7 inches below the top of the tubesheet shall be plugged upon detection.

b. For Unit 1 Refueling Outage 22 and the subsequent operating cycle, tubes with flaws having a circumferential component less than or equal to 203 degrees found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet do not require plugging. Tubes with flaws having a circumferential component greater than 203 degrees found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet shall be removed from service.

   Tubes with service-induced flaws located within the region from the top of the tubesheet to 17 inches below the top of the tubesheet shall be removed from service. Tubes with service-induced axial cracks found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging.

   When more than one flaw with circumferential components is found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet with the total of the circumferential components greater than 203 degrees and an axial separation distance of less than 1 inch, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to count the overlapped portions only once in the total of circumferential components.

   When one or more flaws with circumferential components are found in the portion of the tube within 1 inch from the bottom of the tubesheet, and the total of these circumferential components exceeds 94 degrees, then the tube shall be removed from service. When one or more flaws with circumferential components are found in the portion of the tube within 1 inch from the bottom of the tubesheet and within 1 inch axial separation distance of a flaw above 1 inch from the bottom of the tubesheet, and the total of these circumferential components exceeds 94 degrees, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to count the overlapped portions only once in the total of circumferential components.

c. For Unit 1 Refueling Outage 22 and the subsequent operating cycle, tubes in the B steam generator with permeability variation indications that may mask flaws in the bottom one inch of the tubesheet do not require plugging.

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 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 during Refueling Outage 23 and the subsequent operating cycle, portions of the tube greater than 16.7 inches 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 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 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 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 during Refueling Outage 23 and the subsequent operating cycle, the calculated accident induced LEAKAGE rate from the portion of the tubes below 16.7 inches from the top of the tubesheet for the most limiting accident

in the most limiting SG. In addition, if the calculated accident induced LEAKAGE rate from the most limiting accident is less than 2.03 times the maximum operational primary to secondary LEAKAGE rate, the report should describe how it was determined.

k. For Unit 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 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.

l. Following completion of a Unit 1 inspection performed in Refueling Outage 22 (and any inspections performed in the subsequent operating cycle), the number of indications and location, size, orientation, whether initiated on primary or secondary side for each service-induced flaw within the thickness of the tubesheet, and the total of the circumferential components and any circumferential overlap below 17 inches from the top of the tubesheet as determined in accordance with TS 6.4.Q.3,

m. Following completion of a Unit 1 inspection performed in Refueling Outage 22 (and any inspections performed in the subsequent operating cycle), the primary to secondary LEAKAGE rate observed in each steam generator (if it is not practical to assign leakage to an individual SG, the entire primary to secondary LEAKAGE should be conservatively assumed to be from one steam generator) during the cycle preceding the inspection which is the subject of the report,

n. Following completion of a Unit 1 inspection performed in Refueling Outage 22 (and any inspections performed in the subsequent operating cycle), the calculated accident leakage rate from the portion of the tube 17 inches below the top of the tubesheet for the most limiting accident in the most limiting steam generator, and

o. Following completion of a Unit 1 inspection performed in Refueling Outage 22 (and any other inspections performed in the subsequent operating cycle), for the B steam generator, the number of permeability variation indications including location and total circumferential extent.

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 267 TO

RENEWED FACILITY OPERATING LICENSE NO. DPR-32

AND

AMENDMENT NO. 266 TO RENEWED FACILITY OPERATING LICENSE NO. DPR-37

VIRGINIA ELECTRIC AND POWER COMPANY

SURRY POWER STATION, UNIT NOS. 1 AND 2

DOCKET NOS. 50-280 AND 50-281

1.0 INTRODUCTION

By letter dated July 28, 2009 (Reference 1), to the U.S. Nuclear Regulatory Commission (NRC) the Virginia Electric and Power Company (Dominion) (the licensee), submitted a license amendment request (LAR) to revise the technical specifications (TS) of Surry Power Station (Surry), Units 1 and 2. The request proposed changes to the inspection scope and repair requirements of TS Section 6.4.Q, "Steam Generator (SG) Program," to the reporting requirements of TS Section 6.6.A.3, "Steam Generator (SG) Tube Inspection Report," and to TS Sections 4.13 and 3.1.C, "RCS [Reactor Coolant System] Operational Leakage." The proposed changes would have established permanent alternate repair criteria for portions of the SG tubes within the tubesheet.

By letter dated September 16, 2009 (Reference 2), the licensee responded to requests for additional information from the NRC staff. By letter dated September 30, 2009 (Reference 3), Dominion requested that the alternate repair criteria of the July 28, 2009, letter only be applicable to Unit 1 during Refueling Outage 23 (fall 2010) and the subsequent operating cycle, and to Unit 2 during Refueling Outage 22 (fall 2009) and the subsequent operating cycle.

2.0 BACKGROUND

Surry Unit 1 and 2 have three Model 51F SGs each, which were designed and fabricated by Westinghouse. There are 3,342 thermally treated Alloy 600 tubes in each SG 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 affecting the tubesheet region of thermally treated Alloy 600 tubing had been reported at any nuclear power plants in the United States. In the fall of 2004, crack-like indications were found in tubes in the tubesheet region of Catawba Nuclear Station Unit 2 (Catawba), which has Westinghouse Model D5 SGs. Like Surry Units 1 and 2, the Catawba SGs use thermally treated Alloy 600 tubing that is hydraulically expanded against the tubesheet. The crack-like indications at Catawba were found in a tube overexpansion (OXP), in the tack expansion region, and near the tube-to-tubesheet weld. An OXP is created when the tube is expanded into a tubesheet bore hole that is not perfectly round. These out-of-round conditions were created during the tubesheet drilling process by conditions such as drill bit wandering or chip gouging. The tack expansion is an approximately 1-inch long expansion at each tube end. The purpose of the tack expansion is to facilitate performing the tube-to-tubesheet weld, which is made prior to the hydraulic expansion of the tube over the full tubesheet depth.

Since the initial findings at Catawba in the fall of 2004, other nuclear plants have found crack-like indications in tubes within the tubesheet as well. These plants include Braidwood Unit 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 an LAR that would permanently limit the scope of inspections required for tubes within the tubesheet (Reference 4). 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 RAIs and several meetings with WCNOC, the NRC staff informed WCNOC during a phone call on January 3, 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 5). In a letter dated February 8, 2008 (Reference 6), 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.

Vogtle Electric Generating Plant (VEGP) had also submitted a permanent LAR for Units 1 and 2 (Reference 7) that used the same technical basis as the WCNOC LAR. Upon learning of the NRC staff's denial of the WCNOC permanent LAR, VGEP modified their permanent LAR by letter dated February 13, 2008 (Reference 8), with one-cycle amendment requests for Units 1 and 2 that used a conservative interim alternate repair criteria (IARC) approach. The IARCs for Vogtle Unit 1 and Unit 2 were approved by the NRC on April 9, 2008 (Reference 9), and September 16, 2008 (Reference 10). The NRC also approved one-cycle IARC LARs for Surry Units 1 and 2 in 2008 and 2009 (References 11, 12, and 13).

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 6. The NRC and industry held public meetings (References 14, 15 and 16) and phone calls to discuss resolution of these issues. The permanent LAR received from Dominion in 2009 (Reference 1), resolved the issues identified by the NRC staff in Reference 6 but raised an additional technical issue, as is discussed in Section 4.2.1.3. For this reason, the licensee modified its LAR to apply to Unit 1 during Refueling Outage 23 (fall 2010) and the subsequent operating cycle, and to Unit 2 during Refueling Outage 22 (fall 2009) and the subsequent operating cycle.

3.0 REGULATORY EVALUATION

The SG tubes are part of the reactor coolant pressure boundary (RCPB) and isolate fission products in the primary coolant from the secondary coolant. For the purposes of this safety evaluation, SG tube integrity means that the tubes are capable of performing this safety function in accordance with the plant design and licensing basis. The General Design Criteria (GDC) in Appendix A to Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50 provide regulatory requirements, which are applicable to Surry Units 1 & 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 Units 1 and 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 (Reference 17). Although the plant is exempt from the current GDC, 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 was licensed. Dominion discusses how it meets the design criteria for Surry in Sections 4.1, 4.2, and 4.3 of the Updated Final Safety Analysis Report.

Regulation 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 pressurized water reactor (PWR) facilities (like Surry), ASME Code Class 1 components meet the Section XI requirements of the ASME Code to the extent practical, except for design and access provisions, and pre-service examination requirements. This requirement includes the inspection and repair criteria of Section XI of the ASME Code. The Section XI requirements pertaining to in-service inspection of SG tubing are augmented by additional requirements in the TS. The use of the proposed alternate repair criteria does not impact the integrity of the SG tubes and therefore the SG tubes still meet the design requirements and the requirements for Class 1 components in Section III of the ASME Code.

Analyses addressing the consequences of postulated design-basis accidents (DBA), such as an SG tube rupture and a main steam line break (MSLB) are included in the plant's licensing bases. These analyses consider primary-to-secondary leakage that may occur during these events and must demonstrate that the offsite radiological consequences and control room operator doses do not exceed the applicable limits. The proposed changes do not affect the accident analyses and consequences that the NRC has reviewed and approved for the postulated DBAs for SG tubes.

In 10 CFR 50.36 "Technical Specifications", the requirements for administrative control provisions are established to assure operation of the facility in a safe manner. The TS for all PWR plants require that an SG program be established and implemented to ensure that SG tube integrity is maintained. Programs established by the licensee, including the SG program, are listed in the administrative controls Section of the TS. For Surry Units 1 & 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.

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. Technical specification 6.4.Q.1.a requires that a condition monitoring assessment be performed during each outage in which the SG tubes are inspected, to confirm that the performance criteria are being met. Technical specification 6.4.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 tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet. The applicable tube repair criteria, specified in TS 6.4.Q.3., are that tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40 percent of the nominal wall thickness shall be plugged, unless the tubes are permitted to remain in service through application of the alternate repair criteria provided in TS 6.4.Q.3.a.

In License Amendment Nos. 258 and 263, the provisions for SG tube repair criteria in TS 6.4.Q.1.3. were modified with alternate repair criteria that were applicable during Refueling Outages 21 (Unit 2) and 22 (Unit 1) and the subsequent operating cycle for each plant. The alternate repair criteria approved in amendments Nos. 258 and 263 required full-length inspections of the tubes within the tubesheet but did not require plugging of tubes in which circumferential cracking was observed more than 17 inches below the top of the tubesheet (TTS). Amendment No. 264 was also approved using alternate tube repair criteria for SG B of Unit 1 during Refueling Outage 22 and the subsequent operating cycle. Amendment No. 264 included modified IARC that did not require the plugging of tubes with permeability variations in the bottom 1 inch of the tubesheet, and the TS requirement for primary-to-secondary operational leakage was limited to 20 gallons per day for SG B of Unit 1 during Operating Cycle 23.

The proposed amendment eliminates inspections and repair of tubes more than 16.7 inches below the TTS. Tubes with service-induced flaws located in the portion of the tube from the TTS to 16.7 inches below the TTS shall be plugged upon detection. The proposed amendment would be applicable to Unit 1 during Refueling Outage 23 (fall 2010) and the subsequent operating cycle, and to Unit 2 during Refueling Outage 22 (fall 2009) and the subsequent operating cycle.

4.0 TECHNICAL EVALUATION

4.1 Proposed Changes to the TS

TS 3.1.C.1. is being revised as follows:

d. 150 gallons per day primary to secondary LEAKAGE through any one steam generator (SG).~~, with the following exception. The primary to secondary LEAKAGE for the Unit 1 B steam generator will be limited to 20 gallons per day during Operating Cycle 23.~~

TS 4.13. is being revised as follows (new text in **bold**):

B. Verify primary to secondary LEAKAGE is ≤ 150 gallons per day through any one SG once every 72 hours.[1] ~~, with the following exception. The primary to secondary LEAKAGE for the Unit 1 B steam generator will be verified to be 20 gallons per day during Operating Cycle 23.~~[1] **If it is not practical to assign the LEAKAGE to an individual SG, all the primary-to-secondary LEAKAGE should be conservatively assumed to be from one SG.**

Notes:

1. Not required to be completed until 12 hours after establishment of steady state operation.

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

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

   The following alternate tube repair criteria shall be applied as an alternative to the 40 percent depth based criteria:

   a. **For Unit 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 during Refueling Outage 23 and the subsequent operating cycle, tubes with service-induced flaws located greater than 16.7 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 16.7 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 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 during Refueling Outage 23 and the subsequent operating cycle, portions of the tube greater than 16.7 inches 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 tube may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

   a. [No change/Not shown]

   b. [No change/Not shown]

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

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

3. Steam Generator (SG) 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, SG program. The report shall include:

a. – f. [No change/Not shown]

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

h. The effective plugging percentage for all plugging in each SG,

i. For Unit 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 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 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 during Refueling Outage 23 and the subsequent operating cycle, the calculated accident induced LEAKAGE rate from the portion of the tubes below 16.7 inches from the top of the tubesheet for the most limiting accident in the most limiting SG. In addition, if the calculated accident induced LEAKAGE rate from the most limiting accident is less than 2.03 times the maximum operational primary to secondary LEAKAGE rate, the report should describe how it was determined.

k. For Unit 2 during Refueling Outage 22 and the subsequent operating cycle and for Unit 1 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.

4.2 Technical Evaluation

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

This design basis is a conservative representation of how the T/TS joints actually work, since it conservatively ignores the role of friction between the tube and tubesheet in reacting 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 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 design basis accident 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 Units 1 and 2, the proposed H* distance is 16.7 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.

The regulatory standard by which the NRC has evaluated the subject license amendment is that the amended technical specifications should continue to ensure that tube integrity will be maintained consistent with the current design basis, as defined in the UFSAR. This includes maintaining structural safety margins consistent with the structural performance criteria in TS 6.4.Q.2.a discussed in Section 4.2.1.1 below. In addition, this includes limiting the potential for accident-induced primary-to-secondary leakage to values that do not exceed the accident-induced leakage performance criteria in TS 6.4.Q.2.b, which are consistent with values assumed in the UFSAR accident analyses. Maintaining tube integrity in this manner ensures that the amended TS 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 4.2.1 and 4.2.2 of this safety evaluation, respectively.

4.2.1 Joint Structural Integrity

4.2.1.1 Acceptance Criteria

Westinghouse has conducted extensive analyses to establish the necessary H* distance to resist pullout under normal operating and DBA conditions. The NRC staff finds that pullout is the structural failure mode of interest since the tubes are radially constrained against axial fishmouth rupture by the presence of the tubesheet. The axial force which could produce pullout derives from the pressure end cap loads due to the primary-to-secondary pressure differentials associated with normal operating and DBA conditions. Westinghouse determined the needed H* distance on the basis of maintaining a factor of three against pullout under normal operating conditions and a factor of 1.4 against pullout under DBA conditions. The 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 the ASME Code, Section III.

4.2.1.2 T/TS Interaction Model

The resistance to pullout is the axial friction force developed between the expanded tube and the tubesheet over the H* distance. The friction force is a function of the radial contact pressure between the expanded tube and the tubesheet. Westinghouse used classical thick-shell equations to model the interaction effects between the tubes and tubesheet under various pressure and temperature conditions for purposes of calculating contact pressure (T/TS interaction model). For each tube, the tubesheet was modeled as an equivalent cylinder. The thickness of this equivalent cylinder was calculated to provide a stiffness equivalent to the actual tubesheet geometry in terms of the amount of tubesheet bore radial displacement that is associated with a given amount of radial pressure on the surface of the bore. Two-dimensional (2-D) finite element analyses of portions of the perforated tubesheet geometry were used to determine the thickness of the equivalent tubesheet cylinder that provided the necessary stiffness, as a function of tube location within the bundle. These analyses directly modeled a spectrum of possibilities concerning the pressure loads acting on nearby bore surfaces, instead of employing a "beta factor" adjustment as was done to support previous H* amendment requests submitted prior to 2008. The "beta factor" adjustment was an attempt to account for the pressure loads acting on nearby bore surfaces, which was used in analyses prior to 2008. Based on its review, the NRC staff concludes that the equivalent tubesheet cylinder thicknesses calculated by Westinghouse are conservative since they provide for lower bound stiffness estimates, leading to lower (conservative) estimates of contact pressure and resistance to pullout.

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

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

these finite element analyses is provided in Section 4.2.1.3, below. The tubesheet bore radial displacements from the 3-D finite element analyses were added to those from the tubesheet equivalent shell model to yield the total displacement of the tubesheet bore surface as a function of tube radial and axial location.

The reference T/TS interaction model (Reference 18) assumes as an initial condition that each tube is fully expanded against the tubesheet bore such that the outer tube surface is in contact with the inner surface of the tubesheet bore under room temperature, atmospheric pressure conditions, with zero residual contact pressure associated with the hydraulic expansion process. The NRC staff finds the assumption of zero residual contact pressure in the reference analysis to be a very conservative assumption.

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

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

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

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

4.2.1.3 3-D Finite Element Analysis

A 3-D finite element analysis of the lower SG assembly (consisting of the lower portion of the SG shell, the tubesheet, the channel head, and the divider plate separating the hot and cold leg inlet plenums inside the channel head) was performed to calculate the diameter changes of the tubesheet bore surfaces due to primary pressure acting on the primary face of the tubesheet and SG channel head, secondary pressure acting on the secondary face of the tubesheet and SG shell, and the temperature distribution throughout the entire lower SG assembly. These calculated diameter changes tended to be non-uniform around the circumference of the bore. The thick shell equations used in the T/TS interaction model are axisymmetric. Thus, the non-uniform diameter change from the 3-D finite element analyses had to be adjusted to an equivalent uniform value before it could be used as input to the T/TS interaction analysis. A 2-D plane stress finite element model was used to define a relationship for determining a uniform diameter change that would produce the same change to average T/TS contact pressure as would the actual non-uniform diameter changes from the 3-D finite element analyses.

In Reference 19, Westinghouse identified a difficultly in applying this relationship to Model D5 SGs. In reviewing the reasons for this difficulty, the NRC staff developed questions relating to the conservatism of the relationship and whether the tubesheet bore displacement eccentricities are sufficiently limited such as to ensure that T/TS contact is maintained around the entire tube circumference. However, responses to NRC staff's questions provided in Reference 2 did not provide sufficient information to allow the NRC staff to reach a conclusion on these matters relating to tubesheet bore displacement eccentricity. The licensee, therefore, modified its amendment request on September 30, 2009, (Reference 3) for a permanent H* amendment to be an interim H* amendment request applicable only to the next operating cycle (i.e., Surry Unit 1 during Refueling Outage 23 (fall 2010) and the subsequent operating cycle, and to Surry Unit 2 during Refueling Outage 22 (fall 2009) and the subsequent operating cycle.). Section 4.2.4 provides the NRC staff's evaluation of the interim H* amendment request in light of the open issue relating to tubesheet bore displacement eccentricity. As described in Section 4.2.4, there is sufficient information to enable the NRC staff to evaluate the proposed one-cycle change.

This 3-D finite element analysis replaces the 2-D axisymmetric finite element analyses used to support H* amendment requests submitted prior to 2008. The NRC staff finds that the 3-D analysis adequately addresses a concern cited by the NRC staff in Reference 6 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.

The reference analyses for the Model F SGs assume a linear temperature distribution through the tubesheet. Because the linear distribution does not represent the actual temperature distribution during normal operating conditions, an incremental distance is added to the H* distance to account for the actual tubesheet temperature distribution during normal operating conditions. The Model 51F SGs, however, were analyzed with newer finite element analyses that considered the actual tubesheet temperature distribution during normal operating conditions and thus, did not have an incremental distance added to the H* distance. When the Model F SGs were reanalyzed with the actual tubesheet temperature distribution, the conservatism of the linear temperature distribution was confirmed. While this does account for a minor decrease in the H* distance, the NRC staff concludes that direct modeling of the actual temperature distribution in the tubesheet is more realistic and acceptable.

The reference finite element model used the physical dimensions of the Model F SGs. When the reference finite element model was used to analyze the Model 51F SGs, the model was not redesigned with the dimensions of the Model 51F SG, but was left with the previously used Model F SG dimensions. This was conservative because the inherent stiffness of the Model 51F lower SG assembly (channel head, tubesheet, and divider plate) is greater than that of the Model F SG. The increased stiffness results in less tubesheet deformation due to differential pressure across the tubesheet, which results in less bore-hole distortion at the TTS and a net reduction in the decrease of residual contact pressure (i.e., the residual contact pressure remains higher). Therefore, it is acceptable to use the finite element model that incorporates the more limiting physical dimensions of the Model F SGs.

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

Separate 3-D finite element analyses were conducted for each loading condition considered (i.e., normal operating conditions, MSLB). The feedwater line break accident was not part of the licensing basis for plants with Model 51F SGs (Reference 18) and therefore was not modeled. The NRC staff finds that this adequately addresses (corrects) a significant source of error in analyses used by applicants to support permanent H* amendment requests submitted prior to 2008 and which were subsequently withdrawn or modified (Reference 6).

4.2.1.4 <u>Crevice Pressure Evaluation</u>

As discussed in an earlier footnote, 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. Based on its review of the tests and test results, the NRC staff finds the assumed crevice pressure distributions to be realistic and acceptable.

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

4.2.1.5 H* Calculation Process

The calculation of H* in the reference analyses (Reference 18) consisted of the following steps for each loading case considered:

1. Perform initial H* estimate using the interaction and 3-D finite element models, assuming nominal geometric and material properties, and assuming that the tube is severed at the bottom of the tubesheet for purposes of defining the pressure distribution over the length of the T/TS crevice.
2. 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 analysis. See Section 4.2.1.3 for further discussion.
3. Add 0.3-inch adjustment to the initial H* estimate to account for uncertainty in the bottom of the tube expansion transition (BET) location relative to the top of the tubesheet, based on an uncertainty analysis on the BET conducted by Westinghouse.
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, based on the combined potential variability of key input parameters for the H* analyses. This leads to a "probabilistic" estimate of H*, which is greater than the "mean" estimate calculated in steps 1 through 3.
5. Add a crevice pressure adjustment to the probabilistic estimate of H* to account for the crevice pressure distribution, which results from the tube being severed at the final H* value, rather than at the bottom of the tubesheet. The value of this adjustment was determined iteratively.

The NRC staff's evaluation of the probabilistic analysis is provided in Section 4.2.1.7 of this safety evaluation. Regarding step 3, the NRC staff did not review the Westinghouse BET uncertainty analysis. Therefore, at the NRC staff's request, the licensee has committed to a one-time inspection of the actual BET locations during Refueling Outage 23 for Surry Unit 1 (fall 2010), and during Refueling Outage 22 for Surry Unit 2 (fall 2009) to confirm that there are no significant deviations from the assumed BET value. Any such deviations will be entered into the corrective actions program for disposition. The NRC staff finds this to be acceptable, since the BET inspections are a one-time action that is reviewable during routine NRC regional oversight activities. Any deviations are likely to be small (less than a few tenths of an inch) and not likely to impact the overall conservatism of the proposed H* distance.

4.2.1.6 Acceptance Standard - Probabilistic Analysis

The purpose of the probabilistic analysis is to develop a safe H* distance that ensures with a probability of 0.95 that the population of tubes will retain margins against pullout consistent with criteria evaluated in Section 4.2.1.1 of this safety evaluation, assuming all tubes to be completely severed at their H* distance. The NRC staff finds this probabilistic acceptance standard is consistent with what the 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 20) 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 that have been considered in probabilistic risk assessments (References 21 and 22).

In terms of the confidence level that should be attached to the 0.95 probability acceptance standard, it is industry practice for SG tube integrity evaluations, as embodied in industry guidelines, to calculate such probabilities at a 50 percent confidence level. The Westinghouse recommended H* value of 13.14 inches in Reference 18 for model 51F SGs is based on probabilistic estimates performed at a 50 percent confidence value. However, as discussed in Section 4.2.1.7, the NRC staff finds that the 16.7-inch H* value proposed by the licensee conservatively bounds an H* value based on probabilistic estimates performed at a 95 percent confidence level.

Another issue relating to the acceptance standard for the probabilistic analysis is determining what population of tubes needs to be analyzed. For accidents such as MSLB or FLB, the NRC staff and licensee both find that the tube population in the faulted SG is of interest, since it is the only SG population that experiences a large increase in the primary-to-secondary pressure differential. However, normal operating conditions were found to be the most limiting in terms of meeting the tube pullout margins in Section 4.2.1.1. For normal operating conditions, tubes in all SGs at the plant are subject to the same pressures and temperatures. Although there is not a consensus between the NRC staff and industry on which population needs to be considered in the probabilistic analysis for normal operating conditions, and although the Westinghouse recommended H* value in Reference 18 is based on the population of just one SG, the NRC staff finds that the 16.7-inch H* value proposed by the licensee conservatively bounds an H* value based on probabilistic estimates performed at a 95 percent confidence level for the entire tube population (i.e., for all SGs) at the plant, as discussed in Section 4.2.1.7 below.

4.2.1.7 Probabilistic Analyses

Sensitivity studies were conducted and demonstrated that H* was highly sensitive to the potential variability of the coefficients of thermal expansion (CTE) for the Alloy 600 tubing material and the SA-508 Class 2a tubesheet material. Given that no credit was taken in the reference H* analyses (Reference 18) for residual contact pressure 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 residual contact pressure 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 4.2.1.5), as a function of the variability of each CTE parameter and Young's modulus parameter, relative to the mean values of CTE and Young's Modulus. Separate influence curves were developed for each of the four input parameters. The sensitivity studies showed that of the four input parameters, only the CTE parameters for the tube and tubesheet material had any interaction with one another. A combined set of influence curves containing this interaction effect were also created.

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

The NRC staff reviewed the implementation of probabilistic analyses in the reference analyses (Reference 18) and questioned whether the H* influence curves had been conservatively treated. The NRC staff concluded that the reference analysis was insufficient to support the amendment request. To address this concern, the licensee submitted new H* analyses as documented in Reference 2. These analyses made direct use of the H* influence curves in a manner the NRC staff finds to be acceptable. To show that the proposed H* value in the subject LAR is conservative, the new analyses eliminated some of the conservatisms in the reference analyses as follows:

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

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

2. As discussed previously in Section 4.2.1.3, the new analyses used an updated tubesheet temperature distribution.

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

The new analyses, items 1, 2, and 3 above, also address a question posed by the NRC staff in Reference 6 concerning the appropriate way to sample material properties for the tubesheet, whose properties are unknown but do not vary significantly for a given SG, in contrast to the tubes whose properties tend to vary much more randomly from tube to tube in a given SG. This issue was addressed by a staged sampling process where the tubesheet properties were sampled once and then held fixed, while the tube properties were sampled a number of times equal to the SG tube population. This process was repeated 10,000 times, and the maximum H* value from each repetition was rank ordered. The final H* value was selected from the rank ordering to reflect a 0.95 probability value at the desired level of confidence. The NRC staff concludes that this approach addresses the NRC staff's question in a realistic fashion and is acceptable.

Based on items 1 and 2, and considering the significant conservatism associated with the assumption of zero residual contact pressure, the NRC staff concludes that the proposed H* distance of 16.7 inches for Surry Units 1 and 2 ensures that all tubes will have acceptable pullout resistance for normal operating and design basis accidents, even with the conservative assumption that all tubes are severed at the H* distance.

The licensee has committed to monitor for tube slippage as part of the SG inspection program. Under the proposed license amendment, TS 6.6.A.3.k will require that the results of slippage monitoring be included as part of the 180-day report required by TS 6.6.A.3. TS 6.6.A.3.k will also require that should slippage be discovered, the implications of the discovery and corrective action shall be included in the report. The NRC staff finds that slippage is not expected to occur for the reasons discussed previously. In the unexpected event it should occur, it will be important to understand why it occurred so that the need for corrective action can be evaluated. The NRC staff concludes the commitment to monitor for slippage and the accompanying reporting requirements are acceptable.

4.2.1.8 Coefficient of Thermal Expansion

During operation, a large part of contact pressure in a SG tube-to-tubesheet joint is derived from the difference in the CTE between the tube and tubesheet. As discussed in Section 4.2.1.7, the calculated value of H* is highly sensitive to the assumed values of these CTE parameters. However, CTE test data acquired by an NRC contractor, Argonne National Laboratory (ANL), suggested that CTE values may vary substantially from values listed in the ASME Code for design purposes. In Reference 7, the NRC staff highlighted the need to develop a rigorous technical basis for the CTE values, and their potential variability, to be employed in future H* analyses.

In response, Westinghouse had a subcontractor review the CTE data in question, determine the cause of the variance from the ASME Code CTE values, and provide a summary report (Reference 23). 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 a low temperature, that were not expected. Review of the test data showed that the first test, conducted in a vacuum, had proceeded to a maximum temperature of 700 °C, which changed the microstructure and the CTE of the steel during decreasing temperature conditions. As a result of the altered microstructure, the CTE test data generated in the second test, conducted in air, was also invalidated. As a result of the large "dead band" region and the altered microstructure, both data sets were excluded from the final CTE values obtained from the CTE testing program.

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

The data from the test program were combined with the ANL data that were found by the licensee to be acceptable, and with the data obtained from the open literature search. A statistical analysis of the data uncertainties was performed by comparing deviations to the mean values obtained at the applicable temperatures. The correlation coefficients obtained indicated a good fit to a normal distribution, as expected. Finally, an evaluation of within-heat variability was performed due to increased data scatter at low temperatures. The within-heat variability assessment determined that the increase in data scatter was a testing accuracy limitation that was only present at low temperature. The CTE report is included as Appendix A to Reference 18.

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

Based on its review of Westinghouse CTE program, the NRC staff concludes that the CTE values used in the H* analyses are fully responsive to the concerns stated in Reference 6 and are acceptable.

4.2.2 Accident-induced Leakage Considerations

Operational leakage integrity is assured by monitoring primary-to-secondary leakage relative to the applicable TS LCO limits in TS 3.1.C, "RCS [Reactor Coolant System] 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 tube-to-tubesheet joint mockups to establish loss coefficient as a function of contact pressure. A large amount of data scatter, however, precluded quantification of such a correlation. In the absence of such a correlation, Westinghouse has developed a leakage factor relationship between accident induced leak rate and operational leakage rate, where the source of leakage is from flaws located at or below the H* distance. Using the Darcy model, the leakage factor for a given type accident is the product of four quantities. The first quantity is ratio of the maximum primary-to-secondary pressure difference during the accident divided by that for normal operating conditions. The second quantity is the ratio of viscosity under normal operating primary water temperature divided by viscosity under the accident condition primary water temperature. The third quantity is the ratio of crevice length under normal operating conditions to crevice length under accident conditions. This ratio equals 1, provided it can be shown that positive contact pressure is maintained along the entire H* distance for both conditions. The fourth quantity is the ratio of loss coefficient under normal operating conditions to loss coefficient under the accident condition. Although the absolute value of these loss coefficients isn't known, Westinghouse has assumed that the loss coefficient is constant with contact pressure such that the ratio is equal to 1. The NRC staff agrees that this is a conservative assumption, provided there is a positive contact pressure for both conditions along the entire H* distance and provided that contact pressure increases at each axial location along the H* distance when going from normal operating to accident conditions. Both assumptions were confirmed to be valid in the H* analyses.

Leakage factors were calculated for design basis accidents exhibiting a significant increase in primary-to-secondary pressure differential, including MSLB, locked rotor, and control rod ejection. The design basis MSLB transient was found to exhibit the highest leakage factor, 1.80, meaning that it is the transient expected to result in the largest increase in leakage relative to normal operating conditions.

The licensee provided the following commitment in Reference 2 that describes how the leakage factor will 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:

> *Dominion commits to the following: 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 leakage limit will be established to not exceed the calculated value.*

The NRC staff finds this license commitment acceptable, since it provides further assurance, in addition to the licensee's operational leakage monitoring processes, that accident induced SG tube leakage will not exceed values assumed in the licensing bases accident analyses. The NRC staff finds that the leakage factor of 2.03 conservatively bounds the increase in leakage from locations below the H* distance that may be induced by accident conditions relative to leakage from the same locations under normal operating conditions.

Additionally, the licensee committed to plug 11 tubes in Unit 2, during Refueling Outage 22, that have been identified as not being expanded within the tubesheet in either the hot-leg or cold-leg, and to plug 3 tubes in Unit 1, during Refueling Outage 23, that have been identified as not being expanded within the tubesheet in either the hot-leg or cold-leg. The staff finds this acceptable since the H* methodology was not designed for use on an unexpanded SG tube.

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

The NRC staff has reviewed the proposed revised reporting requirements and finds that they, in conjunction with existing reporting requirements, are sufficient to allow the NRC staff to monitor the condition of the SG tubing as part of its review of the 180-day inspection reports, which are generally completed within 18 months after the reports are submitted. Based on this conclusion, the NRC staff finds that the proposed revised reporting requirements are in accordance with 10 CFR 50.36(c)(5) and are acceptable.

4.2.4 Technical Bases for Interim H* Amendment

The proposed H* value is based on the conservative assumption that all tubes in all 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 residual contact pressure associated with the tube hydraulic expansion process.

As discussed in Section 4.2.1.3, the NRC staff does not have sufficient information to determine whether the tubesheet bore displacement eccentricity has been addressed in a conservative fashion. Thus, in spite of the significant conservatisms embodied in the proposed H* distance, the

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. However, the licensee is now requesting an interim amendment that is applicable to Unit 1 during Refueling Outage 23 (fall 2010) and the subsequent operating cycle, and to Unit 2 during Refueling Outage 22 (fall 2009) and the subsequent operating cycle, rather than an amendment that is applicable to the remaining life of the plants. The NRC staff finds that assuming all tubes will be severed at the H* distance over the next operating cycle to be unrealistic and that the proposed H* distance is conservative for the next operating cycle for the reasons cited below.

From a fleet-wide perspective (for all Westinghouse plants with tubes fabricated from thermally treated Alloy 600), the NRC staff has observed from operating experience that the extent of cracking is at an early stage in terms of the number of tubes affected by cracking below the H* distance and the severity of cracks, compared to the idealized assumption that all tubes are severed at the H* distance. Most of these cracks occur in the lower-most 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 cracking in the fleet will continue to be limited to a small percentage of tubes, mostly near the tube ends. 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 documented generally within 18 months of each SG tube inspection. Reference 24 provides a recent example of such a review for Surry Unit 1 by the NRC staff.

Because Surry Unit 1 and 2 received SG interim alternate repair criteria amendments (References 11 and 13), they were required to perform full depth tubesheet inspections in their most recent refueling outages. In Reference 3, the licensee stated that the most recent inspections of the Surry SGs included approximately 24,725 tube ends and 216 flaw indications were found. All indications were located in hot-leg side of the SGs. These indications were located within 1 inch of the tube ends and resulted in plugging of 12 tubes in Unit 1 and 6 tubes in Unit 2. During the spring 2009 Unit 1 Refueling Outage, eddy current exam identified an axial flaw in the expansion transition of SG A. The affected tube was part of a small population of tubes with high residual stress due to a fabrication anomaly (Reference 25). The tube was plugged and the remaining population of high stress tubes (43) was inspected and found to be without flaws. In addition, over 50 percent of the overexpansion/ bulge indications within the tubesheet were inspected in both Unit 1 and 2 during the most recent inspections and no degradation was found. The licensee also stated in Reference 3 that no primary-to-secondary SG tube leakage has been reported during the current operating cycles. The NRC staff notes that although Surry has accumulated slightly more operating time than other units in the fleet (in terms of effective full power years), the Surry Units operate at a relatively low hot-leg temperature so crack activity is expected to be within the envelope of fleet experience. Aside from the isolated flaw mentioned above, no indications of cracking were found at other locations relatively susceptible to stress corrosion cracking (e.g., at tube expansion transitions or other tube geometry discontinuity locations) at the Surry units, such as that observed at other units in the fleet. Given the limited amount of indications that have been found at Surry Units 1 and 2, the NRC staff concludes that the extent and severity of cracking 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 the next operating cycle for the reasons discussed above. The NRC staff also concludes there is reasonable assurance that until the next scheduled inspection any potential accident induced leakage will not exceed the technical specification 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 4.2.2 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.

5.0 SUMMARY

The NRC staff finds that the proposed amendment request acceptably addresses all issues identified by the NRC staff in Reference 6 relating to H* amendment requests submitted prior to 2008 (which were subsequently withdrawn or modified). However, the NRC staff does not have sufficient information to determine whether the tubesheet bore displacement eccentricity has been addressed in a conservative fashion and, thus, the NRC staff does not have an adequate basis to approve a permanent H* amendment. Accordingly, the licensee modified its amendment request on September 30, 2009 to be an interim amendment request, applicable to Unit 1 during Refueling Outage 23 (fall 2010) and the subsequent operating cycle, and to Unit 2 during Refueling Outage 22 (fall 2009) and the subsequent operating cycle.

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

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 and change surveillance requirements. 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 previously issued a proposed finding that the amendments involve no significant hazards consideration, and there has been no public comment on such finding (74 FR 41939). Accordingly, the amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the 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

References:

1. Dominion letter 09-455, "Proposed License Amendment Request for Permanent Alternate Repair Criteria for Steam Generator Tube Repair for Units 1 and 2," July 28, 2009, NRC ADAMS Accession No. ML092150464. This letter also transmitted Reference 18.

2. Dominion letter 09-455A, September 16, 2009, responding to Surry Power Station Unit 1 and 2 RAIs, NRC ADAMS No. ML092660615. This letter also transmitted Westinghouse Electric Company (WEC) letter LTR-SGMP-09-108 P-Attachment and NP-Attachment, "Response to NRC Request for Additional Information on H*; Model 44F and 51F Steam Generators," August 27, 2009, NRC ADAMS Accession No. ML092660616. The September 16, 2009, letter also contained, "Attachment 3 - Corrected pages for WCAP-17092-NP (Non-proprietary)," June 30, 2009, NRC ADAMS No. ML092660617. WCAP-17092-NP is Reference 18.

3. Dominion letter 09-455B, September 30, 2009, amending its H* application to be a one-time change," September 30, 2009, NRC ADAMS Accession No. ML092800358.

4. Wolf Creek Nuclear Operating Corporation, Letter ET-06-004, "Revision to Technical Specification 5.5.9, "Steam Generator Tube Surveillance Program,"" February 21, 2006, NRC ADAMS Accession No. ML060600456.

5. Wolf Creek Nuclear Operating Corporation, letter ET-08-0010, "Withdrawal of License Amendment Request for a Permanent Alternate Repair Criteria in Technical Specification (TS) 5.5.9, "Steam Generator (SG) Program" February 14, 2008, NRC ADAMS Accession No. ML080580201.

6. NRC letter to Wolf Creek Nuclear Operating Corporation, Wolf Creek Generating Station – Withdrawal of License Amendment Request on Steam Generator tube Inspections," February 28, 2008, NRC ADAMS Accession No. ML080450185.

7. SNC letter NL-07-1710, Vogtle Electric Generating Plant Units 1 and 2 License Amendment Request to Technical Specification (TS) Sections TS 5.5.9, "Steam Generator (SG) Program" and TS 5.6.10, "Steam Generator Tube Inspection Report," November 30, 2007, NRC ADAMS Accession No. ML073380100.

8. SNC letter NL-08-0148, Vogtle Electric Generating Plant Units 1 and 2 License Amendment Request to Revise Technical Specification (TS) Sections TS 5.5.9, "Steam Generator (SG) Program" and TS 5.6.10, "Steam Generator Tube Inspection Report" for Interim Alternate Repair Criterion, February 13, 2008, NRC ADAMS Accession No. ML080500223.

9. NRC letter to SNC, Vogtle Electric Generating Plant, Units 1 And 2, Issuance of Amendments Regarding Changes to Technical Specification (TS) Sections Ts 5.5.9, Steam Generator (SG) Program" and TS 5.6.10, "Steam Generator Tube Inspection Report, April 9, 2008, NRC Accession No. ML080950247.

10. NRC letter to SNC, Vogtle Electric Generating Plant, Units 1 And 2, Issuance of Amendments Regarding Steam Generator Tube Inspection Program, September 16, 2008, NRC Accession No. ML082530044.

11. NRC letter to Dominion, "Surry, Unit 1, Issuance of Amendment Regarding Proposed License Amendment Request - Interim Alternate Repair Criteria for Steam Generator Tube Repair," April 08, 2009, NRC Accession No. ML090860735.

12. NRC letter to Dominion, "Surry Power Station, Unit 1 - Issuance of Amendment Regarding Modified Interim Alternate Repair Criteria for B Steam Generator Tube Repair," May 07, 2009, NRC Accession No. ML091260386.

13. NRC letter to Dominion, "Surry Power Station, Unit 2 - Issuance of Exigent Amendment Regarding Interim Alternate Repair Criteria for Steam Generator Tube Repair," May 16, 2008, NRC Accession No. ML081340068.

14. NRC Meeting minutes, "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," NRC ADAMS Accession No. ML083300422.

15. NRC Meeting minutes, "Summary of the January 9, 2009, Category 2 Public Meeting with the U.S. Nuclear Industry Representatives to Discuss Steam Generator H*/B* Issues," NRC ADAMS Accession No. ML090370945.

16. NRC Meeting minutes, "Summary of the April 3, 2009, Category 2 Public Meeting with the U.S. Nuclear Industry Representatives to Discuss Steam Generator H* Issues," April 30, 2009, NRC ADAMS Accession No. ML091210437.

17. SECY-92-223, "Resolution of Deviations Identified During the Systematic Evaluation Program," September 18, 1992, NRC ADAMS Accession No. ML003763736.

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

19. WEC letter LTR-SGMP-09-66, "White Paper: Low Temperature Seam Line Break Contact Pressure and Local Tube Bore Deformation Analysis for H*," May 13, 2009, NRC ADAMS Accession No. ML092610439.

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

21. 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.

22. NUREG-1570, "Risk Assessment of Severe Accident-Induced Steam Generator Tube Rupture," March 1998.

23. Nuclear Energy Institute letter dated July 7, 2009, NRC ADAMS Accession No. ML082100086, transmitting Babcock and Wilcox Limited Canada letter 2008-06-PK-001, "Re-assessment of PMIC measurements for the determination of CTE of SA 508 steel," dated June 6, 2009, NRC ADAMS Accession No. ML082100097.

24. NRC letter to Dominion, "Surry Power Station Unit No. 1, 2007 Refueling Outage Steam Generator Tube Inspections," December 8, 2008, NRC ADAMS Accession No. ML083380628.

25. NRC Information Notice 2002-21, "Supplement 1: Axial Outside-Diameter Cracking Affecting Thermally Treated Alloy 600 Steam Generator Tubing," April 1, 2003, NRC ADAMS Accession No. ML030900517

Principal Contributor: Andrew Johnson

Date of issuance: November 5, 2009

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/

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

Docket Nos. 50-280 and 50-281

Enclosures:
1. Amendment No. 267 to DPR-32
2. Amendment No. 266 to DPR-37
3. Safety Evaluation

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ADAMS Accession No. ML092960484 * SE by memo dated ** with comments

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