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

May 3, 2010

Mr. David A. Heacock
President and Chief Nuclear Officer
Dominion Nuclear Connecticut, Inc.
Innsbrook Technical Center
5000 Dominion Boulevard
Glen Allen, VA 23060-6711

SUBJECT: MILLSTONE POWER STATION, UNIT NO. 3 – ISSUANCE OF AMENDMENT RE: CHANGES TO THE STEAM GENERATOR INSPECTION SCOPE AND REPAIR REQUIREMENTS (TAC NO. ME2978)

Dear Mr. Heacock:

The Commission has issued the enclosed Amendment No. 249 to Facility Operating License No. NPF-49 for Millstone Power Station, Unit No 3 (MPS3). This amendment consists of changes to the Technical Specifications (TSs) in response to your application dated November 23, 2009, and supplemented by letter dated April 26, 2010.

The amendment changes the inspection scope and repair requirements of TS Section 6.8.4.g, "Steam Generator (SG) Program," and the reporting requirements of TS Section 6.9.1.7, "Steam Generator Tube Inspection Report." The changes establish interim alternate repair criteria for portions of the SG tubes within the tubesheet. This amendment is applicable for Refueling Outage 13, which began in April 2010, and the subsequent operating cycle.

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

Sincerely,

Carleen J. Sanders, Project Manager
Plant Licensing Branch I-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-423

Enclosures:
1. Amendment No. 249 to NPF-49
2. Safety Evaluation

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

DOMINION NUCLEAR CONNECTICUT, INC., ET AL.

DOCKET NO. 50-423

MILLSTONE POWER STATION, UNIT NO. 3

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 249
Renewed License No. NPF-49

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

   A. The application for amendment by the applicant dated November 23, 2009, as supplemented by letter dated April 26, 2010, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

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

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

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

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

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Renewed Facility Operating License No. NPF-49 is hereby amended to read as follows:

   (2) Technical Specifications

   The Technical Specifications contained in Appendix A, as revised through Amendment No. 249, and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto, are hereby incorporated in the renewed license. DNC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of the date of issuance, and shall be implemented within 30 days of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

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

Attachment: Changes to the License
and Technical Specifications

Date of Issuance: May 3, 2010

ATTACHMENT TO LICENSE AMENDMENT NO. 249

RENEWED FACILITY OPERATING LICENSE NO. NPF-49

DOCKET NO. 50-423

Replace the following page of the Renewed Facility Operating License with the attached revised page. The revised page is identified by amendment number and contains marginal lines indicating the areas of change.

Remove	Insert
4	4

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

Remove	Insert
6-17b	6-17b
6-17c	6-17c
6-21	6-21
6-21a	6-21a

(2) Technical Specifications

The Technical Specifications contained in Appendix A, revised through Amendment No. 249 and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto are hereby incorporated into the license. DNC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) DNC shall not take any action that would cause Dominion Resources, Inc. (DRI) or its parent companies to void, cancel, or diminish DNC's commitment to have sufficient funds available to fund an extended plant shutdown as represented in the application for approval of the transfer of the licenses for MPS Unit No. 3.

(4) Immediately after the transfer of interests in MPS Unit No. 3 to DNC, the amount in the decommissioning trust fund for MPS Unit No. 3 must, with respect to the interest in MPS Unit No. 3, that DNC would then hold, be at a level no less than the formula amount under 10 CFR 50.75.

(5) The decommissioning trust agreement for MPS Unit No. 3 at the time the transfer of the unit to DNC is effected and thereafter is subject to the following:

(a) The decommissioning trust agreement must be in a form acceptable to the NRC.

(b) With respect to the decommissioning trust fund, investments in the securities or other obligations of Dominion Resources, Inc. or its affiliates or subsidiaries, successors, or assigns are prohibited. Except for investments tied to market indexes or other non-nuclear-sector mutual funds, investments in any entity owning one or more nuclear power plants are prohibited.

(c) The decommissioning trust agreement for MPS Unit No. 3 must provide that no disbursements or payments from the trust, other than for ordinary administrative expenses, shall be made by the trustee until the trustee has first given the Director of the Office of Nuclear Reactor Regulation 30 days prior written notice of payment. The decommissioning trust agreement shall further contain a provision that no disbursements or payments from the trust shall be made if the trustee receives prior written notice of objection from the NRC.

(d) The decommissioning trust agreement must provide that the agreement can not be amended in any material respect without 30 days prior written notification to the Director of the Office of Nuclear Reactor Regulation.

PROCEDURES AND PROGRAMS (Continued)

Leakage is not to exceed 500 gpd per SG.

3. The operational LEAKAGE performance criterion is specified in RCS LCO 3.4.6.2, "Operational LEAKAGE."

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

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

1. For Refueling Outage 13 and the subsequent operating cycle, tubes with service-induced flaws located greater than 13.1 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 13.1 inches below the top of the tubesheet shall be plugged upon detection.

PROCEDURES AND PROGRAMS (Continued)

d. Provisions for SG tube inspections: Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. For Refueling Outage 13 and the subsequent operating cycle, portions of the tube below 13.1 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 d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

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

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

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

6.9.1.6.c The core operating limits shall be determined so that all applicable limits (e.g. fuel thermal-mechanical limits, core thermal-hydraulic limits, ECCS limits, nuclear limits such as SHUTDOWN MARGIN, and transient and accident analysis limits) of the safety analysis are met.

6.9.1.6.d The CORE OPERATING LIMITS REPORT, including any mid-cycle revisions or supplements thereto, shall be provided upon issuance, for each reload cycle, to the NRC Document Control Desk with copies to the Regional Administrator and Resident Inspector.

STEAM GENERATOR TUBE INSPECTION REPORT

6.9.1.7 A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with TS 6.8.4.g, 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. During Refueling Outage 13 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,

STEAM GENERATOR TUBE INSPECTION REPORT (Continued)

j. During Refueling Outage 13 and the subsequent operating cycle, the calculated accident induced leakage rate from the portion of the tubes below 13.1 inches from the top of the tubesheet for the most limiting accident in the most limiting SG. In addition, if the calculated accident induced leakage rate from the most limiting accident is less than 2.49 times the maximum operational primary to secondary leakage rate, the report should describe how it was determined; and

k. During Refueling Outage 13 and the subsequent operating cycle, the results of monitoring for tube axial displacement (slippage). If slippage is discovered, the implications of the discovery and corrective action shall be provided.

SPECIAL REPORTS

6.9.2 Special reports shall be submitted to the U.S. Nuclear Regulatory Commission, Document Control Desk, Washington, D.C. 20555, one copy to the Regional Administrator Region I, and one copy to the NRC Resident Inspector, within the time period specified for each report.

6.10 Deleted.

6.11 RADIATION PROTECTION PROGRAM

6.11.1 Procedures for personnel radiation protection shall be prepared consistent with the requirements of 10 CFR Part 20 and shall be approved, maintained, and adhered to for all operations involving personnel radiation exposure.

6.12 HIGH RADIATION AREA

As provided in paragraph 20.1601(c) of 10 CFR Part 20, the following controls shall be applied to high radiation areas in place of the controls required by paragraph 20.1601 (a) and (b) of 10 CFR Part 20:

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NUMBER 249

TO FACILITY OPERATING LICENSE NUMBER NPF-49

MILLSTONE POWER STATION, UNIT NO. 3

DOCKET NUMBER 50-423

1.0 INTRODUCTION

By letter dated November 23, 2009, as supplemented by letter dated April 26, 2010, Dominion Nuclear Connecticut, Inc. (DNC or the licensee) submitted a license amendment request (LAR) to revise the technical specifications (TSs) of Millstone Power Station, Unit No. 3 (MPS3) (Reference 1 and 2, respectively). The request proposed changes to the inspection scope and repair requirements of TS Section 6.8.4.g, "Steam Generator (SG) Program" and to the reporting requirements of TS Section 6.9.1.7, "Steam Generator Tube Inspection Report." The proposed changes would establish alternate repair criteria for portions of the SG tubes within the tubesheet and would be applicable to Refueling Outage 13 (RFO13), which began in April 2010, and the subsequent operating cycle. As such, the proposed amendment would be applicable to SG tube inspections performed during RFO13.

As a result of reviewing previous SG eddy current inspection findings, DNC submitted the April 26, 2010, letter. The supplement dated April 26, 2010, provided additional information that clarified the application but did not expand the scope of the application as originally noticed, and did not change the NRC staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on January 26, 2010 (75 FR 4114).

The November 23, 2009, request transmitted technical basis document WCAP-17071, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model F)" (Reference 3), provided by Westinghouse Electric Company, LLC (Westinghouse), and responses to U.S. Nuclear Regulatory Commission (NRC) staff requests for additional information (RAIs) (References 4 and 5) that were asked when WCAP-17071 was initially submitted to support a similar amendment for the Vogtle Electric Generating Plant (Vogtle), Units 1 and 2, which is owned by Southern Nuclear Operating Company (SNC).

2.0 BACKGROUND

MPS3 has four Model F SGs that were designed and fabricated by Westinghouse. There are 5,626 Alloy 600 tubes in each SG, each with a nominal outside diameter of 0.688 inches, and a nominal wall thickness of 0.040 inches. The thermally-treated tubes are hydraulically expanded for the full depth of the 21-inch tubesheet and are welded to the tubesheet at each tube end.

Until the fall of 2004, no instances of stress-corrosion cracking (SCC) 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 MPS3, 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 (T/TS) weld. An OXP is created when the tube is expanded into a tubesheet bore hole that is not perfectly round. These out-of-round conditions were created during the tubesheet drilling process by conditions such as drill bit wandering or chip gouging. The tack expansion is approximately 1-inch long at each tube end. The purpose of the tack expansion is to facilitate performing the T/TS weld, which is made prior to the hydraulic expansion of the tube over the full tubesheet depth.

Since the initial findings at Catawba, other nuclear plants have found crack-like indications in tubes within the tubesheet. These plants include: Braidwood Station, Unit 2; Byron Station, Unit 2; Comanche Peak Steam Electric Station, Unit 2; Surry Power Station, Unit 2; Vogtle, Unit 1; and Wolf Creek Generating Station (Wolf Creek). 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 SCC.

On February 21, 2006, Wolf Creek Nuclear Operating Corporation (WCNOC), the licensee for Wolf Creek, submitted an LAR that would permanently limit the scope of inspections required for tubes within the tubesheet (Reference 6). 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 sufficient information had not been provided to allow the NRC staff to approve the permanent LAR. WCNOC withdrew the LAR by letter dated February 14, 2008 (Reference 7). In a letter dated February 28, 2008 (Reference 8), the NRC staff identified the specific issues that needed to be addressed to support any future request for a permanent amendment.

SNC, the licensee for Vogtle, had also submitted an LAR that would permanently limit the scope of inspections required for tubes within the tubesheet (Reference 9). SNC's submittal used the same technical basis as the WCNOC LAR. Upon learning of the withdrawal of the WCNOC permanent LAR, SNC modified its permanent LAR by letter dated February 13, 2008 (Reference 10), to make the inspection change for only one cycle. This modification 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 11), and September 16, 2008 (Reference 12).

After SNC received approval of the IARC amendments, several licensees submitted and gained approval of one-cycle IARC amendments which used a more conservative approach. MPS3 currently has an approved one-cycle IARC amendment (Reference 13).

Subsequently, the licensees and Westinghouse worked with the NRC staff to address the issues posed in Reference 8. The NRC and industry held public meetings (References 14, 15, and 16) and phone calls to discuss resolution of these issues.

The MPS3 LAR, submitted by DNC on November 23, 2009, has addressed the issues previously identified by the NRC staff in Reference 8 and is for one 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 Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix A, state that the RCPB shall have "an extremely low probability of abnormal leakage of rapidly propagating failure, and of gross rupture" (GDC 14), "shall be designed with sufficient margin" (GDCs 15 and 31), shall be of "the highest quality standards practical" (GDC 30), and shall be designed to permit "periodic inspection and testing of important areas and feature to assess their structural and leaktight integrity" (GDC 32). The licensee discusses conformance with each of these GDCs for MPS3 in Section 3.1.2 of the Updated Final Safety Analysis Report (UFSAR) and does not identify deviations from these GDC for SG tube-related issues.

In 10 CFR 50.55a, it 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 MPS3), 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 inservice 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 description of conformance with the GDC in 10 CFR Part 50, Appendix A, provided in the MPS3 UFSAR, and the requirements for Class 1 components in Section III of the ASME Code.

Analyses addressing the consequences of postulated design-basis accidents (DBAs), such as a SG tube rupture and a main steam line break (MSLB), are included in the plant's licensing basis. 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 NRC staff reviewed and approved accident analyses and consequences for the postulated SG tube DBAs

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. For MPS3, the requirements for performing SG tube inspections and repair are in TS 6.8.4.g, while the requirements for reporting the SG tube inspections and repair are in TS 6.9.1.7.

SG tube integrity is maintained by meeting the performance criteria specified in TS 6.8.4.g.b for structural and leakage integrity, consistent with the plant design and licensing basis.
TS 6.8.4.g.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. TS 6.8.4.g.d includes provisions regarding the scope, frequency, and methods of SG tube inspections. These provisions require that the inspections be performed with the objective of detecting flaws of any type that may be present along the length of a tube, from the T/TS weld at the tube inlet to the T/TS weld at the tube outlet. The applicable tube repair criteria, specified in TS 6.8.4.g.c, are that tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40 percent of the nominal wall thickness shall be plugged, unless the tubes are permitted to remain in service through application of the alternate repair criteria, also provided in TS 6.8.4.g.c.

In License Amendment No. 245, the provisions for SG tube repair criteria, currently shown in TS 6.8.4.g.c., were modified with interim alternate repair criteria that were applicable during MPS3 RFO 12 and the subsequent operating cycle. The IARC excluded some indications of primary water SCC in the lowermost 4 inches of the tubesheet from application of the 40-percent, depth-based, tube-repair criterion. The proposed amendment eliminates inspection and repair of tubes more than 13.1 inches below the top of the tubesheet (TTS). Tubes with service-induced flaws located in the portion of the tube from the TTS to 13.1 inches below the TTS shall be plugged upon detection. The proposed amendment for these alternate inspection and repair criteria would be applicable to SG tube inspections performed during RFO13 and the subsequent operating cycle.

4.0 TECHNICAL EVALUATION

4.1 Proposed Changes to the TSs

TS 6.8.4.g.c. is being revised as follows (new text in *italics*):

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

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

1. For Refueling Outage 13 and the subsequent operating cycle, tubes with service-induced flaws located greater than 13.1 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 13.1 inches below the top of the tubesheet shall be plugged upon detection.

TS 6.8.4.g.d. is being revised as follows (new text in *italics*):

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

tube repair criteria. *For Refueling Outage 13 and the subsequent operating cycle, portions of the tube below 13.1 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 d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

1. [No change/Not shown]

2. [No change/Not shown]

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

TS 6.9.1.7 is being revised as follows (new text in *italics*):

A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with TS 6.8.4.g, Steam Generator (SG) Program. The report shall include:

a. – h. [No change/Not shown]

i. *During Refueling Outage 13 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,*

j. *During Refueling Outage 13 and the subsequent operating cycle, the calculated accident induced leakage rate from the portion of the tubes below 13.1 inches from the top of the tubesheet for the most limiting accident in the most limiting SG. In addition, if the calculated accident induced leakage rate from the most limiting accident is less than 2.49 times the maximum operational primary to secondary leakage rate, the report should describe how it was determined; and*

k. *During Refueling Outage 13 and the subsequent operating cycle, the results of monitoring for tube axial displacement (slippage). If slippage is discovered, the implications of the discovery and corrective action shall be provided.*

4.2 Technical Evaluation

The T/TS joints are part of the pressure boundary between the primary and secondary systems. Each T/TS joint consists of the tube, which is hydraulically expanded against the bore of the tubesheet, the T/TS weld located at the tube end, and the tubesheet. The joints were designed in accordance with 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 reducing the tube end-cap loads that are transmitted to the T/TS weld. 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 (H*) to be a certain distance below the TTS. H* is the distance below the TTS over which sufficient frictional force, with acceptable safety margins, can be developed between each tube and the tubesheet, under tube end-cap pressure loads associated with normal operating and DBA conditions, to prevent significant slippage or pullout of the tube from the tubesheet, assuming the tube is fully severed at the H* distance below the TTS. For MPS3, the proposed H* distance is 13.1 inches. Given that the frictional force developed in the T/TS joint over the H* distance is sufficient to resist the tube end-cap pressure loads, it is the licensee's and Westinghouse's position that the length of tubing between the H* distance and the T/TS weld is not needed to resist any portion of the tube end-cap pressure loads. Thus, the licensee is proposing to change the 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 TTS to a distance below the TTS equal to H* for purposes of evaluating the structural and leakage integrity of the joint.

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

4.2.1.2 *T/TS Interaction Model*

The resistance to pullout is the axial friction force developed between the expanded tube and the tubesheet over the H* distance. The friction force is a function of the radial contact pressure between the expanded tube and the tubesheet. Westinghouse used classical thick-shell equations to model the interaction effects between the tubes and tubesheet under various pressure and temperature conditions for the purpose 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 H* amendment requests submitted prior to 2008. Based on its review, the NRC staff concludes that the equivalent tubesheet cylinder thicknesses calculated by Westinghouse are conservative since they provide for lower bound stiffness estimates, leading to lower (conservative) estimates of contact pressure and resistance to pullout.

The shell model representing the tube was used to determine the relationship between the tube outer surface radial displacement and the applied axial end-cap load (due to the primary-to-secondary pressure differential), primary pressure acting on the tube inner surface, crevice pressure[1] acting on the tube outer surface, contact pressure between the tube and tubesheet bore, and tube thermal expansion. However, the equivalent shell model representing the tubesheet was used only to determine the relationship between the tubesheet bore surface radial displacement with the applied crevice pressure and contact pressure. Radial

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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.

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

The reference T/TS interaction model (Reference 2) assumes, as an initial condition, that each tube is fully expanded against the tubesheet bore such that the outer tube surface is in contact with the inner surface of the tubesheet bore under room temperature, atmospheric pressure conditions, with zero 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 equals 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 TTS, 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 TTS to the distance below the TTS 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 21, 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 to ensure that T/TS contact is maintained around the entire tube circumference. The response to the NRC staff's questions provided in References 4 and 5 did not provide sufficient information to allow the staff to reach a conclusion on the concerns relating to tubesheet bore displacement eccentricity. However, as described in Section 4.2.5, 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 8 concerning the validity of the axisymmetric model to conservatively bound significant non-axisymmetric features of the actual tubesheets. These non-axisymmetric features include the solid (non-bored) portion of the tubesheet between the hot- and cold-leg sides, and the divider plate which acts to connect the solid part of the tubesheet to the channel head.

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

Separate 3-D finite element analyses were conducted for each loading condition considered (i.e., normal operating conditions, MSLB, feedwater line break (FLB)). The NRC staff finds that

this adequately addresses (corrects) a significant source of error in analyses used by applicants to support permanent H* amendment requests submitted prior to 2008. These requests were subsequently withdrawn or modified.

4.2.1.4 *Crevice Pressure Evaluation*

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

For tubes which do not contain through-wall flaws within the thickness of the tubesheet, the pressure inside the crevice is assumed to be equal to the secondary system pressure. For tubes that contain through-wall flaws within the thickness of the tubesheet, a leak path is assumed to exist, from the primary coolant inside the tube, through the flaw, and up the crevice to the secondary system. Hydraulic tests were performed 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 TTS and the H* distance below the TTS 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 TTS, where crevice pressure equals secondary pressure, an initial assumption as to the H* location must be made before solving for H* using the T/TS interaction model and 3-D finite element model. The resulting new H* estimate becomes the initial estimate for the next H* iteration.

4.2.1.5 *H* Calculation Process*

The calculation of H* in the reference analyses (Reference 3), consisted of the following steps for each loading case considered:

1. Perform initial H* estimate using the interaction and 3-D finite element models, assuming nominal geometric and material properties, and assuming that the tube is severed at the

bottom of the tubesheet for purposes of defining the pressure distribution over the length of the T/TS crevice.

2. Add 0.3 inches to the initial H* estimate to account for the crevice depth. The crevice depth is the distance from the TTS to the bottom of the tube expansion transition (BET). The 0.3 inch value was based on an uncertainty analysis of the crevice depth on Model F SGs that was conducted by Westinghouse.[2]

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

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

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

The NRC staff's evaluation of the probabilistic analysis is provided in Section 4.2.1.7 of this safety evaluation.

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 22) 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 23 and 24).

In terms of the confidence level that should be attached to the 0.95 probability acceptance standard, it is industry practice for SG tube integrity evaluations, as embodied in industry guidelines, to calculate such probabilities at a 50 percent confidence level. The Westinghouse recommended H* value of 11.2 inches in Reference 3 for Model F SGs is based on probabilistic estimates performed at a 50 percent confidence value. However, as discussed in

[2] As a result of plant specific measurements made at MPS3, the crevice depth distance was increased from 0.3 inches to 1.0 inch. See Section 4.2.4 for further discussion.

Section 4.2.1.7, the NRC staff finds that the 13.1 inch H* value proposed by the licensee conservatively bounds an H* value based on probabilistic estimates performed at a 95 percent confidence value.

Another issue relating to the acceptance standard for the probabilistic analysis is determining what population of tubes need 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 3 is based on the population of just one SG, the NRC staff finds that the 13.1 inch H* value proposed by the licensee conservatively bounds an H* value based on probabilistic estimates performed at a 95 percent confidence 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 3) for residual contact pressure associated with the tube hydraulic expansion process,[3] 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.

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

The NRC staff reviewed the implementation of probabilistic analyses in the reference analyses (References 3 and 21) and questioned whether the H* influence curves had been conservatively treated. The NRC staff concluded that the reference analyses were insufficient to support the amendment request. To address this concern, the licensee submitted new H* analyses as documented in References 5 and 25 (although Reference 25 was submitted on the Vogtle docket, the reference is bounding for the SGs at MPS3). 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 results in a more realistic estimate, but still provides a conservative H*.

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

3. The reference analyses take no credit for 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 states that the tests confirm a significant level of residual contact pressure, and showed that within a small degree of slippage, the forces required to continue moving the tube by far exceeded the maximum pullout forces that could be generated under very conservative assumptions. The licensee finds that crediting this latest information, in conjunction with the sector analysis discussed in item 1 and the updated correction discussed in item 2 (based on direct modeling of the temperature distribution in the tubesheet), leads to a further, significant reduction in the calculated H* value relative to values calculated in items 1 and 2. This information, including the latest

pullout test data, has not been reviewed in detail by the NRC staff. However, the 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 8 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 above, and considering the significant conservatism associated with the assumption of zero residual contact pressure, the NRC staff concludes that the proposed H* distance of 13.1 inches for MPS3 ensures that all tubes will have acceptable pullout resistance for normal operation and DBAs, even with the conservative assumption that all tubes are severed at the H* distance.

The licensee will monitor for tube slippage as part of the SG inspection program. Under the proposed license amendment, TS 6.9.1.7.k will require that the results of slippage monitoring be included as part of the 180-day report required by TS 6.9.1.7. TS 6.9.1.7.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 licensee's plan to monitor for slippage and the accompanying reporting requirements are acceptable.

4.2.1.8 *Coefficient of Thermal Expansion*

During operation, a large part of contact pressure in an SG T/TS 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 8, 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 26). 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 method, the mean CTE values determined were in good agreement with the established ASME Code values.

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

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

The data from the test program were combined with the ANL data that were found by the licensee to be acceptable, and with the data obtained from the open literature search. A statistical analysis of the data uncertainties was performed by comparing deviations to the mean values obtained at the applicable temperatures. The correlation coefficients obtained indicated a good fit to a normal distribution, as expected. Finally, an evaluation of within-heat variability was performed due to increased data scatter at low temperatures. The within-heat variability assessment determined that the increase in data scatter was a testing accuracy limitation that was only present at low temperature. The CTE report is included as Appendix A to References 3 and 21.

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 8 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 limiting condition for operation limits in TS 3.4.6, "Reactor Coolant System 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 6.8.4.g.b.2, including the leakage values assumed in the plant licensing basis accident analyses.

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

Westinghouse performed leak tests of T/TS joint mockups to establish the 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 the 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 is not known, Westinghouse has assumed that the loss coefficient is constant with contact pressure such that the ratio is equal to 1. The NRC staff agrees that this is a conservative assumption, provided there is a positive contact pressure for both conditions along the entire H* distance and provided that contact pressure increases at each axial location along the H* distance when going from normal operating to accident conditions. Both assumptions were confirmed to be valid in the H* analyses.

Leakage factors were calculated for DBAs exhibiting a significant increase in primary-to-secondary pressure differential, including MSLB, FLB, locked rotor, and control rod ejection. The design-basis FLB heat-up transient was found to exhibit the highest leakage factor, 2.49, 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 information in Reference 3 that describes how the leakage factor will be used to satisfy TS 6.8.4.g.a for Condition Monitoring and TS 6.8.4.g.b.2 regarding performance criteria for accident-induced leakage:

> For the Condition Monitoring assessment, the component of operational leakage from the prior cycle from below the H* distance will be multiplied by a factor of 2.49 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 2.49 and compared to the observed operational leakage. An administrative limit will be established to not exceed the calculated value.

The NRC staff finds this methodology acceptable, since it provides further assurance, in addition to the licensee's operational leakage monitoring processes, that accident-induced SG tube leakage will not exceed values assumed in the licensing bases accident analyses. The NRC staff finds that the leakage factor of 2.49 conservatively bounds the increase in leakage from locations below the H* distance that may be induced by accident conditions relative to leakage from the same locations under normal operating conditions.

4.2.3 *Proposed Change to TS 6.9.1.7, "Steam Generator Tube Inspection Report"*

The NRC staff has reviewed the proposed new reporting requirements and finds that they, in conjunction with existing reporting requirements, are sufficient to allow the NRC staff to monitor the condition of the SG tubing as part of its review of the 180-day inspection reports. Based on this conclusion, the NRC staff finds that the proposed new reporting requirements are in accordance with 10 CFR 50.36 and are acceptable.

4.2.4 *Increased crevice depth distances*

In April 2010, the NRC staff held several phone calls with DNC personnel to discuss the results of a review of SG eddy current inspection data. The review was performed to compare the actual crevice depths for the MPS3 SGs tubes, to the crevice depth of 0.3 inches that was assumed in the reference H* analyses. This review was performed to meet a commitment made in the November 23, 2009, letter. During the calls, the licensee informed the NRC staff that some MPS3 SG tubes had crevice depths greater than 0.3 inches, with depths ranging up to 1.74 inches.

DNC requested Westinghouse assess the effect of crevice depths greater than 0.3 inches on the conservatism of the proposed H* value, calculated on a 0.95 probability/95 percent confidence interval, whole plant basis. Although Westinghouse did not perform new Monte Carlo analyses considering crevice depths greater than 0.3 inches, due to the significant amount of time required for the analyses, they did provide a technical justification (Reference 2) for measured crevice depths up to 1.0 inch. In Reference 2, Westinghouse concluded that the requested inspection depth of 13.1 inches provides significant margin over a 0.95 probability/95 percent confidence interval, whole plant value, which does not consider the effect of residual contact pressure to accommodate crevice depths up to 1.0 inch. Westinghouse also concluded that the margin, between the requested inspection depth and the calculated H* values, increases as the position of the tube in the bundle varies from the limiting position in the tubesheet (which the H* value is based on). In addition, Westinghouse concluded that an increase of the crevice depth to a value of 1.0 inch below the TTS (compared to the 0.3 inch uncertainty already included in the calculated values of H*), is readily accommodated by the

available margin between the requested inspection depth of 13.1 inches and the calculated H* values.

DNC stated that seven tubes in SG 'A' have crevice depths greater than 1.0 inch. DNC stated that there are no crevice depths greater than 1.0 inch in any other SG. The licensee has indicated that the full length of the 7 tubes with crevice depth greater than 1.0 inch were inspected during RFO12 (Fall 2008) and that the tubes contained no indications of degradation[4]. SG 'A' was not scheduled for inspection during RFO13. Given that the RFO12 inspections showed no degradation in SG 'A', that inspections in SGs 'B' and 'D' during RFO13 did not result in inspection scope expansion into SGs 'A' and 'C', and that this amendment is only applicable for RFO13 and the subsequent operating cycle, the NRC staff finds that there is reasonable assurance that these seven tubes in SG 'A' satisfy the structural and leakage performance criteria. DNC has committed to remove the seven tubes from service no later than the next scheduled inspection.

Given the limited extent of degradation found in the MPS3 SGs and the technical justification in Reference 2, the NRC staff finds that the 13.1-inch H* distance for the Model F SGs at MPS3 provides reasonable assurance that tube integrity will be maintained, even with crevice depths of up to and including 1.0 inch, for RFO13 and the subsequent operating cycle.

4.2.5 *Technical Bases for Interim H* Amendment*

The proposed H* value is based on the conservative assumption that all tubes in all SGs are severed at the H* location. 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 SGs, assuming all tubes to be severed at the H* location. However, the licensee is requesting an interim amendment that is applicable only during RFO13 and the subsequent operating cycle, rather than an amendment that is applicable to the remaining life of the plant. The TS state that "No SG shall operate for more than 48 effective full power months or two refueling outage (whichever is less) without being inspected." An operating cycle is the period of time between refueling outages. The NRC staff finds that assuming all tubes will be severed at the H* distance over a period of 48 months 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. This is 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

[4] DNC affirmed this information in an email dated April 28, 2010 (Agencywide Documents Access and Management System Accession No. ML101180473)

lower-most 1 inch of tubing, which is a region of relatively high residual stress associated with the 1-inch tack roll expansion in that region. Although the extent of cracking can be expected to increase with time, it is the NRC staff's judgment, based on experience, that it will continue to be limited to a small percentage of tubes, mostly near the tube ends, over the next operating cycle. 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 after each SG tube inspection. Reference 27 provides a recent example of such a review by the NRC staff.

In the fall of 2008, approximately 5900 tubes of the hot-leg expansion transitions in SGs 'A' and 'C' were inspected at MPS3 and no crack-like indications were found. A sample of 700 cold-leg expansion transitions were also inspected in SGs 'A' and 'C' and no crack-like indications were found. Tube-end inspections included 17,889 tubes in the hot-legs of SGs 'A', 'B', 'C', and 'D', and an additional 8,924 tubes in the four SG cold-legs. These tube-end inspections revealed 99 axial indications and 53 circumferential indications that resulted in 23 tubes being plugged (Reference 28). The NRC staff finds that the extent and severity of cracking at MPS3 to be within the envelope of industry experience with similar units.

The NRC staff concludes that there is sufficient conservatism embodied in the proposed H* distance to ensure acceptable margins against tube pullout during RFO13 and the subsequent operating cycle for the reasons discussed above. The NRC staff also concludes there is reasonable assurance, during the next operating cycle, that any potential accident-induced leakage will not exceed the TS performance criteria for accident-induced leakage. This reflects current operating experience trends that cracking below the H* distance is occurring predominantly in the tack roll region near the bottom of the tube. At this location, it is the NRC staff's judgment that the total resistance to primary-to-secondary leakage will be dominated by the resistance of any "crevice" in the roll expansion region (due to very high regional T/TS contact pressures). This consideration of primary-to-secondary leakage maintains the validity of the conservative leakage factors discussed in Section 4.2.2 should there be a loss of T/TS contact near the TTS due to tubesheet bore eccentricity effects.

4.3 *Technical Evaluation Conclusions*

The NRC staff finds that the proposed amendment request acceptably addresses all issues identified by the staff in Reference 8. Notwithstanding any potential non-conservatism in the calculated H* distance which may be associated with the eccentricity issue, and also accounting for an assumed crevice depth of 1.0 inch, the staff concludes that, given the current state of the tubes, there is sufficient conservatism embodied in the proposed H* distance to ensure, for the period requested by the licensee, 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 finds the proposed amendment to be acceptable.

Consistent with the changes approved in this amendment, the alternate inspection and repair criteria are applicable to SG tube inspections performed during RFO13 and the subsequent operating cycle.

5.0 STATE CONSULTATION

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

6.0 ENVIRONMENTAL CONSIDERATION

The amendment changes a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration, and there has been no public comment on such finding (75 FR 4114). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

7.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner; (2) such activities will be conducted in compliance with the Commission's regulations; and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

8.0 REFERENCES

1. Dominion Nuclear Connecticut, Inc, Letter 09-525, "Millstone Power Station Unit 3 License Amendment Request To Revise Technical Specification (TS) 6.8.4.g, "Steam Generator (SG) Program," and TS 6.9.1.7, "Steam Generator Tube Inspection Report" for One-Time Alternate Repair Criteria (H*), November 23, 2009, ADAMS Accession No. ML093620085. This letter also transmitted References 2, 3, and 4.

2. DNC, Letter 10-276, "Millstone Power Station Unit 3 License Amendment Request To Revise TS 6.8.4.g, 'Steam Generator (SG) Program,' and TS 6.9.1.7, 'Steam Generator Tube Inspection Report' for One-Time Alternate Repair Criteria (H*) Submittal of Supplemental Information," April 26, 2010, ADAMS Accession No. ML101190416.

3. Westinghouse Electric Company, LLC, (WEC) WCAP-17071-P (Proprietary) and WCAP-17071-NP (Non-Proprietary), "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model F)", Revision 0, dated April 2009, ADAMS Accession Nos. ML093620087 (Proprietary) and ML093620086 (Non-Proprietary).

4. WEC letter LTR-SGMP-09-100 P-Attachment (Proprietary) and LTR-SGMP-09-100 NP-Attachment (Non-Proprietary) "Response to NRC Request for Additional Information

on H*; Model F and D5 Steam Generators," dated August 12, 2009, ADAMS Accession Nos. ML093620087 (Proprietary) and ML093620086 (Non-Proprietary).

5. WEC letter LTR-SGMP-09-109 P-Attachment (Proprietary) and LTR-SGMP-09-109 NP-Attachment (Non-Proprietary) Attachment "Response to NRC Request for Additional Information on H*; RAI #4; Model F and Model D5 Steam Generators," dated August 25, 2009, ADAMS Accession Nos. ML093620087 (Proprietary) and ML093620086 (Non-Proprietary).

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

7. 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, ADAMS Accession No. ML080580201.

8. 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, ADAMS Accession No. ML080450185.

9. 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, ADAMS Accession No. ML073380100.

10. 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, ADAMS Accession No. ML080500223.

11. 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, ADAMS Accession No. ML080950247.

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

13. NRC letter to DNC, "Millstone Power Station, Unit No.3 - Issuance of Amendment Regarding Changes to Technical Specification (TS) Section 6.8.4.g, "Steam Generator Program" and Section 6.9.1.7, "Steam Generator Tube Inspection Report," September 30, 2008, ADAMS Accession No. ML082321292.

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," 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," 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, ADAMS Accession No. ML091210437.

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

18. SNC letter NL-09-1375, August 28, 2009, responding to Vogtle RAI No. 4 and transmitting WEC letter SGMP-09-109-P, "Response to NRC Request for Additional Information on H*; RAI #4; Model F and Model D5 Steam Generators," as an attachment, NRC ADAMS Accession No. ML092450333.

19. SNC letter NL-09-1265, August 28, 2009, responding to Vogtle RAIs and transmitting WEC letter LTR-SGMP-09-100-P (Proprietary) and LTR-SGMP-09-100-NP (Non-Proprietary) "Response to NRC Request for Additional Information on H*; Model F and D5 Steam Generators," dated August 12, 2009, NRC ADAMS Accession Nos. ML092450102 (Proprietary) and ML092450101 (Non-Proprietary).

20. SNC letter NL-09-1411, September 11, 2009, amending its H* application to apply only to the next operating cycle, NRC ADAMS Accession No. ML092540511.

21. Westinghouse Electric Company report, WCAP-17072-P (Proprietary) and WCAP-17072-NP (Non-Proprietary), Rev. 0, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model D5)," May 2009, ADAMS Accession Nos. ML091670159 (Introduction through Section 6.2.2.2.2 - Proprietary), ML091670160 (Section 6.2.2.2.3 through Section 6.2.5.3 - Proprietary), ML091670161 (Section 6.2.6 through Appendix), and ML091670172 (Non- Proprietary).

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

23. 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.

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

25. SNC letter NL-09-1317, August 28, 2009, transmitting WEC letter LTR-SGMP-09-104-P Attachment "White Paper on Probabilistic Assessment of H*" dated August 13, 2009, ADAMS Accession Nos. ML092450030 (Proprietary) and ML092450029 (Non-Proprietary).

26. Nuclear Energy Institute letter dated July 7, 2009, 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, ADAMS Accession No. ML082100097.

27. NRC memorandum, "Millstone Power Station, Unit No.3 - Review of the 2008 Steam Generator Tube Inservice Inspection Report" December 22, 2009, ADAMS Accession No. ML093500669.

28. DNC letter 09-125, "Millstone Power Station Unit 3 End of Cycle 12 Steam Generator Tube Inspection Report, March 13, 2009, ADAMS Accession No. ML090850344.

Principal Contributors: E. Murphy, NRR
A. Johnson, NRR

Date: May 3, 2010

May 3, 2010

Mr. David A. Heacock
President and Chief Nuclear Officer
Dominion Nuclear Connecticut, Inc.
Innsbrook Technical Center
5000 Dominion Boulevard
Glen Allen, VA 23060-6711

SUBJECT: MILLSTONE POWER STATION, UNIT NO. 3 – ISSUANCE OF AMENDMENT RE: CHANGES TO THE STEAM GENERATOR INSPECTION SCOPE AND REPAIR REQUIREMENTS (TAC NO. ME2978)

Dear Mr. Heacock:

The Commission has issued the enclosed Amendment No. 249 to Facility Operating License No. NPF-49 for Millstone Power Station, Unit No 3 (MPS3). This amendment consists of changes to the Technical Specifications (TSs) in response to your application dated November 23, 2009, as supplemented by letter dated April 26, 2010.

The amendment changes the inspection scope and repair requirements of TS Section 6.8.4.g, "Steam Generator (SG) Program," and the reporting requirements of TS Section 6.9.1.7, "Steam Generator Tube Inspection Report." The changes establish interim alternate repair criteria for portions of the SG tubes within the tubesheet. This amendment is applicable for Refueling Outage 13, which began in April 2010, and the subsequent operating cycle.

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

Sincerely,
/RA/
Carleen J. Sanders, Project Manager
Plant Licensing Branch I-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-423

Enclosures:
1. Amendment No. 249 to NPF-49
2. Safety Evaluation

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ADAMS Accession No.: ML100770358 *by memo dated ^by email dated

OFFICE	LPL1-2/PM	LPL1-2/LA	CSGB/BC	DIRS/ISTB	OGC NLO w/ comments	LPL1-2/BC
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