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

September 30, 2008

Mr. David A. Christian
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 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" (TAC NO. MD8736)

Dear Mr. Christian:

The Nuclear Regulatory Commission has issued the enclosed Amendment No. 245 to Renewed Facility Operating License No. NPF-49 for the Millstone Power Station, Unit No. 3, in response to your application dated May 8, 2008 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML081490087), as supplemented by letter dated August 14, 2008 (ADAMS Accession No. ML0823103300).

The amendment changes the repair requirements of Technical Specification (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 proposed changes would establish alternate repair criteria for portions of the SG tubes within the tubesheet, and would be applicable to Millstone Power Station, Unit No. 3 during Refueling Outage 12 and the subsequent operating cycle only.

A copy of the related 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. 245 to NPF-49
2. Safety Evaluation

cc w/encls: See next page

Millstone Power Station, Unit No. 3

cc:

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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. 245
Renewed License No. NPF-49

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

   A. The application for amendment by the applicant dated May 8, 2008, as supplemented by letter dated August 14, 2008, 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.245 , 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 prior to Mode 5 startup of Millstone Power Station, Unit 3.

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: September 30, 2008

ATTACHMENT TO LICENSE AMENDMENT NO. 245

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
Page 4	Page 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
xix	xix
6-17b	6-17b
6-17c	6-17c
------	6-17d
------	6-17e
6-18	6-18
6-21	6-21
6-21a	6-21a
------	6-21b

(2) Technical Specifications

The Technical Specifications contained in Appendix A, revised through Amendment No245and 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.

ADMINISTRATIVE CONTROLS

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 MPS3 Refueling Outage 12 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

PROCEDURES AND PROGRAMS (Continued)

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.

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

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

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

3. If crack indications are found in any 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.

e. Provisions for monitoring operational primary to secondary LEAKAGE.

h. Control Room Envelope Habitability Program

A Control Room Envelope (CRE) Habitability Program shall be established and implemented to ensure that CRE habitability is maintained such that, with an OPERABLE Control Room Emergency Ventilation System (CREVs), CRE occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. The program shall ensure that adequate radiation protection is provided to permit access and occupancy of the CRE under design basis accident (DBA) conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent (TEDE) for the duration of the accident. The program shall include the following elements:

a. The definition of the CRE and the CRE boundary.

b. Requirements for maintaining the CRE boundary in its design condition including configuration control and preventive maintenance.

c. Requirements for (i) determining the unfiltered air inleakage past the CRE boundary into the CRE in accordance with the testing methods and at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, "Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors," Revision 0, May 2003, and (ii) assessing CRE habitability at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0.

The following are exceptions to Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0:

1. Appropriate application of ASTM E741 shall include the ability to take minor exceptions to the test methodology. These exceptions shall be documented in the test report, and

2. Vulnerability assessments for radiological, hazardous chemical and smoke, and emergency ventilation system testing were completed as documented in the UFSAR and other licensing basis documents. The exceptions to the Regulatory Guides (RG) referenced in RG 1.196 (i.e., RG 1.52, RG 1.78, and

PROCEDURES AND PROGRAMS (Continued)

RG 1.183), which were considered in completing the vulnerability assessments, are documented in the UFSAR/current licensing basis. Compliance with these RGs is consistent with the current licensing basis as described in the UFSAR and other licensing basis documents.

d. Measurement, at designated locations, of the CRE pressure relative to all external areas adjacent to the CRE boundary during the pressurization mode of operation by one train of the CREVs, operating at the flow rate required by the Surveillance Requirements, at a Frequency of 48 months on a STAGGERED TEST BASIS. The results shall be trended and used as part of the 24 month assessment of the CRE boundary.

e. The quantitative limits on unfiltered air inleakage into the CRE. These limits shall be stated in a manner to allow direct comparison to the unfiltered air inleakage measured by the testing described in paragraph c. The unfiltered air inleakage limit for radiological challenges is the inleakage flow rate assumed in the licensing basis analyses of DBA consequences. Unfiltered air inleakage limits for hazardous chemicals must ensure that exposure of CRE occupants to these hazards will be within the assumptions in the licensing basis.

The provisions of Surveillance Requirement 4.0.2 are applicable to the Frequencies for assessing CRE habitability, determining CRE unfiltered inleakage, and measuring CRE pressure and assessing the CRE boundary as required by paragraphs c. and d., respectively.

6.8.5 Written procedures shall be established, implemented and maintained covering Section I.E, Radiological Environmental Monitoring, of the REMODCM.

6.8.6 All procedures and procedure changes required for the Radiological Environmental Monitoring Program (REMP) of Specification 6.8.5 above shall be reviewed by an individual (other than the author) from the organization responsible for the REMP and approved by appropriate supervision.

Temporary changes may be made provided the intent of the original procedure is not altered and the change is documented and reviewed by an individual (other than the author) from the organization responsible for the REMP, within 14 days of implementation.

6.9 REPORTING REQUIREMENTS

ROUTINE REPORTS

6.9.1 In addition to the applicable reporting requirements of Title 10, Code of Federal Regulations, the following 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, unless otherwise noted.

STARTUP REPORT

6.9.1.1 A summary report of plant startup and power escalation testing shall be submitted following: (1) receipt of an Operating License, (2) amendment to the license involving a planned increase in power level, (3) installation of fuel that has a different design or has been manufactured by a different fuel supplier, and (4) modifications that may have significantly altered the nuclear, thermal, or hydraulic performance of the unit.

The Startup Report shall address each of the tests identified in the Final Safety Analysis Report and shall include a description of the measured values of the operating conditions or characteristics obtained during the test program and a comparison of these values with design predictions and specifications. Any corrective actions that were required to obtain satisfactory operation shall also be described. Any additional specific details required in license conditions based on other commitments shall be included in this report.

Startup Reports shall be submitted within: (1) 90 days following completion of the Startup Test Program, (2) 90 days following resumption or commencement of commercial power operation, or (3) 9 months following initial criticality, whichever is earliest. If the Startup Report does not cover all three events (i.e., initial criticality, completion of Startup Test Program, and resumption or commencement of commercial operation), supplementary reports shall be submitted at least every 3 months until all three events have been completed.

ANNUAL REPORTS*

6.9.1.2 Annual Reports covering the activities of the unit as described below for the previous calendar year shall be submitted in accordance with 10 CFR 50.4.

6.9.1.2a. Deleted

6.9.1.2b. The results of specific activity analyses in which the reactor coolant exceeded the limits of Specification 3.4.8. The following information shall be included: (1) Reactor power history starting 48 hours prior to the first sample in which the limit was exceeded (in graphic and tabular format); (2) Results of the last isotopic analysis for radioiodine performed prior to exceeding the limit, results of analysis while the limit was exceeded and results of one analysis after the radioiodine activity was reduced to less than the limit. Each result should include date and time of sampling and the radioiodine concentrations; (3) Clean-up flow history starting 48 hours prior to the first sample in which the limit was exceeded; (4) Graph of the I-131 concentration (μCi/gm) and one other radioiodine isotope concentration (μCi/gm) as a function of time for the

* A single submittal may be made for a multiple unit station. The submittal should combine those sections that are common to all units at the station.

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. Following completion of an inspection performed in Refueling Outage 12 (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,

STEAM GENERATOR TUBE INSPECTION REPORT (Continued)

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 6.8.4.g.c,

j. Following completion of an inspection performed in Refueling Outage 12 (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, and

k. Following completion of an inspection performed in Refueling Outage 12 (and any inspections performed in the subsequent operating cycle), the calculated accident leakage rate from the portion of the tube below 17 inches from the top of the tubesheet for the most limiting accident in the most limiting steam generator.

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:

6.12 HIGH RADIATION AREA (Continued)

6.12.1 High Radiation Areas with Dose Not Exceeding 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation

a. Each entryway to such an area shall be barricaded and conspicuously posted as a high radiation area. Such barricades may be opened as necessary to permit entry or exit of personnel or equipment.

b. Access to, and activities in, each such area shall be controlled by means of a Radiation Work Permit (RWP) or equivalent; that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

c. Individuals qualified in radiation protection procedures and personnel continuously escorted by such individuals may be exempted from the requirement for an RWP or equivalent while performing their assigned duties provided that they are otherwise following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall possess:

1. A radiation monitoring device that continuously displays radiation dose rates in the area, or

2. A radiation monitoring device that continuously integrates the radiation dose rates in the area and alarms when the device's dose alarm setpoint is reached, with an appropriate alarm setpoint, or

3. A radiation monitoring device that continuously transmits dose rate and cumulative dose information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area, or

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 245

TO RENEWED FACILITY OPERATING LICENSE NO. NPF-49

DOMINION NUCLEAR CONNECTICUT, INC.

MILLSTONE POWER STATION, UNIT NO. 3

DOCKET NO. 50-423

1.0 INTRODUCTION

By letter dated May 8, 2008 (Agencywide Document Access and Management System (ADAMS) Accession No. ML081490087), as supplemented by letter dated August 14, 2008 (ADAMS Accession No. ML0823103300) Dominion Nuclear Connecticut, Inc., (DNC or the licensee) submitted a license amendment request to change the technical specifications (TS) for Millstone Power Station, Unit No. 3 (MPS3). The request proposed changes to the 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 MPS3 during Refueling Outage 12 (3R12) and the subsequent operating cycle (Cycle 13) only.

The Nuclear Regulatory Commission (NRC) staff published a proposed no significant hazards consideration determination in the *Federal Register* on July 8, 2008 (73 FR 39054).

The supplement dated August 14, 2008, clarified the application, did not expand the scope of the original Federal Register notice and did not change the initial proposed no significant hazards consideration determination.

In its letters dated May 8, 2008, and August 14, 2008, the licensee submitted Westinghouse Electric Company (WEC) topical reports, LTR-CDME-08-11 P-Attachment, "Interim Alternate Repair Criterion (IARC) for Cracks in the Lower Region of the Tubesheet Expansion Zone," dated January 31, 2008, and LTR-CDME-08-43 P-Attachment, "Response to NRC Request for Additional Information Relating to LTR-CDME-08-11 P-Attachment." The topical reports contained proprietary information and affidavits, signed by the licensee and requesting that the NRC withhold the proprietary information from the public, were also submitted in these letters. The NRC letters approving the withholding of the information from the public, in accordance with Title 10 of the *Code of Federal Regulations* (10 CFR), Paragraph 2.390(b)(5) and Section 103(b) of the Atomic Energy Act of 1954, as amended, were issued in letters dated

August 22, 2008 (ADAMS Accession No. ML082310663, for LTR-CDME-08-43-P) and August 13, 2008 (ADAMS Accession No. ML0810821306060, for LTR-CDME-08-11-P. There is no proprietary information in this safety evaluation (SE).

2.0 BACKGROUND

Millstone Power Station, Unit No. 3, has four Model F SGs designed and fabricated by Westinghouse. There are 5626 tubes in each SG, each with an outside diameter of 0.688 inches and a nominal wall thickness of 0.040 inches. The tubes are thermally treated alloy 600 and are hydraulically expanded for the full depth of the tubesheet (21.03 inches) at each end and are welded to the tubesheet at the bottom of each expansion.

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 plant in the United States. As a result, most plants, including MPS3, had been using bobbin probes for inspecting the length of tubing within the tubesheet. Since bobbin probes are not capable of reliably detecting SCC in the tubesheet region, supplementary rotating coil probe inspections were used in a region extending from 3 inches above the top of the tubesheet (TTS) to 3 inches below the TTS. This zone includes the tube-expansion transition, which contains significant residual stress, and was considered a likely location for SCC to develop.

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 employ thermally treated alloy 600 tubing that is hydraulically expanded against the tubesheet. At the time of cracking, Catawba had accumulated 14.7 effective full power years (EFPY) of service, which is less than the service experience that the SGs at MPS3 have currently accumulated, with a comparable hot-leg operating temperature. The crack-like indications at Catawba were found in bulges (also called over-expansions) in the tubesheet region, in the tack expansion region, and near the tube-to-tubesheet weld. 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.

As a result of the Catawba findings, DNC expanded the scope of rotating coil inspections in overexpansions (OXPs). OXPs are created when tubes are expanded into small diametrical variances in the holes that are bored in the tubesheet. During the fall 2005 MPS3 refueling outage, 207 tubes in SGs 'A' and 'C' with over 1000 OXPs were inspected and no indications of SCC were found. In spring 2007, rotating coil inspections were performed in 407 tubes in SGs 'B' and 'D', and no indications of SCC were found.

3.0 REGULATORY EVALUATION

In 10 CFR 50.36, the Commission established its regulatory requirements related to the content of the TSs. Pursuant to 10 CFR 50.36, TSs are required to include items in the following five specific categories related to station operation: (1) safety limits, limiting safety system settings, and limiting control settings; (2) limiting conditions for operation (LCOs); (3) surveillance requirements; (4) design features; and (5) administrative controls. The rule does not specify the particular requirements to be included in a plant's TSs. In 10 CFR 50.36(d)(5), administrative controls are stated to be "the provisions relating to organization and management, procedures, recordkeeping, review and audit, and reporting necessary to assure the operation of the facility in a safe manner." This also includes the programs established by the licensee and listed in the administrative controls section of the TSs for the licensee to operate the facility in a safe manner. The requirements for (1) SG tube inspections and repair, and (2) reporting on these inspections and repair for MPS3 are in TS 3.4.5, "Steam Generator (SG) Tube Integrity," and TS 6.8.4.g, and TS 6.9.1.7, respectively.

The TS for all pressurized water reactor (PWR) plants require that an SG program be established and implemented to ensure that SG tube integrity is maintained. For MPS3, SG tube integrity is maintained by meeting specified performance criteria (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 also includes provisions regarding the scope, frequency, and methods of SG tube inspections. Of relevance to the subject amendment request, these provisions require that the inspections be performed with the objective of detecting flaws of any type that may be present along the length of a tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. The applicable tube repair criteria, specified in TS 6.8.4.g.c, are that tubes found by an inservice inspection (ISI) to contain flaws with a depth equal to or exceeding 40 percent of the nominal tube-wall thickness shall be plugged.

The SG tubes function as an integral part of the reactor coolant pressure boundary (RCPB) and, in addition, serve to isolate radiological fission products in the primary reactor coolant from the secondary coolant and the environment. For the purposes of this SE, SG tube integrity means that the tubes are capable of performing these safety functions in accordance with the plant design and licensing basis.

As part of the plant licensing basis, applicants for PWR licenses are required to analyze the consequences of postulated design-basis accidents (DBAs) such as an SG tube rupture and main steam line break (MSLB). These analyses consider primary-to-secondary leakage which may occur during these events and must show that the offsite radiological consequences do not exceed the applicable limits of the Title 10 of the *Code of Federal Regulations* (10 CFR) Part 100 guidelines for offsite doses, General Design Criteria (GDC) 19 criteria for control room operator doses, or some fraction thereof as appropriate to the accident, or the NRC-approved licensing basis (e.g., a small fraction of these limits). No new unanalyzed accident is introduced by the license amendment request, thus, no radiological consequences of any accident analysis are being changed.

MPS3 is constructed to 'NRC General Design Criteria for Nuclear Power Plants, Appendix A to 10 CFR 50, as amended through October 27, 1978,' as stated in the MPS3 Updated Final Safety Analysis Report. The GDC provides regulatory requirements which state that the RCPB shall have "an extremely low probability of abnormal leakage . . . and 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 . . . to assess . . . structural and leaktight integrity" (GDC 32). To this end, 10 CFR 50.55a specifies that components which are part of the RCPB must meet the requirements for Class 1 components in Section III of the American Society of Mechanical Engineers *Boiler and Pressure Vessel* Code (ASME Code). Section 50.55a further requires, in part, that throughout the service life of a PWR facility like MPS3, ASME Code Class 1 components meet the requirements, except design and access provisions and pre-service examination requirements, in Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," of the ASME Code, to the extent practical. This requirement includes the inspection and repair criteria of Section XI of the ASME Code. Section XI requirements that pertain to the ISI of SG tubing are augmented by additional requirements in the TSs.

The licensee-proposed changes to TS 6.8.4.g stay within the GDC requirements for the SG tubes and maintain the accident analysis and consequences that the NRC has reviewed and approved for the postulated DBAs for SG tubes. The proposed amendment is applicable to 3R12 (planned for fall 2008) and the subsequent operating cycle.

4.0 TECHNICAL EVALUATION

4.1 Proposed Changes to the TSs

TS 6.8.4.g.c currently states:

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 criterion would be revised as follows, as noted in italic type:

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 MPS3 Refueling Outage 12 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.

TS 6.9.1.7 currently states:

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

TS 6.9.1.7 would be revised to add the following three reporting criteria, as noted in italics:

i. Following completion of an inspection performed in Refueling Outage 12 (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 6.8.4.g.c,

j. Following completion of an inspection performed in Refueling Outage 12 (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 SG) during the cycle preceding the inspection which is the subject of the report, and*

k. *Following completion of an inspection performed in Refueling Outage 12 (and any inspections performed in the subsequent operating cycle), the calculated accident leakage rate from the portion of the tube below 17 inches from the top of the tubesheet for the most limiting accident in the most limiting steam generator.*

4.2 Technical Evaluation

The tube-to-tubesheet joint consists of the tube, which is hydraulically expanded against the bore of the tubesheet; the tube-to-tubesheet weld located at the tube end; and the tubesheet. The joint was designed as a welded joint and not as a friction or expansion joint. The weld itself was designed as a pressure boundary element. It was designed to transmit the entire end-cap pressure load during normal and DBA conditions from the tube to the tubesheet with no credit taken for the friction developed between the hydraulically expanded tube and the tubesheet. In addition, the weld serves to make the joint leak tight.

The proposed amendment treats the tube-to-tubesheet joint as a welded joint in a manner consistent with the original design basis, with no credit taken for the friction developed between the hydraulically expanded tube and the tubesheet. The proposed amendment is intended to ensure that the aforementioned end-cap loads can be transmitted down the tube, through the tube-to-tubesheet weld, and into the tubesheet.

4.2.1 Proposed Change to TS 6.8.4.g.c, "Provisions for SG tube repair criteria"

MPS3's current TS 6.8.4.g.c states that "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 40 percent depth-based tube repair criterion in TS 6.8.4.g.c is intended to ensure, in conjunction with other elements of TS 6.8.4.g, that tubes accepted for continued service (i.e., not plugged) satisfy the performance criteria for structural integrity in TS 6.8.4.g.b.1 and the performance criteria for accident leakage integrity in TS 6.8.4.g.b.2. The criterion includes an allowance for eddy current measurement error and incremental flaw growth prior to the next inspection of the tube. The alternate tube repair criteria in the current TSs and the proposed IARC in the proposed amendment are alternatives to the 40 percent depth-based criterion.

4.2.1.1 Structural Integrity Considerations

The 40 percent depth-based criterion was developed to be conservative for flaws located anywhere in the SG, including free span regions. In the tubesheet, however, the tubes are constrained against radial expansion by the tubesheet and, therefore, are constrained against an axial (fish-mouth) rupture failure mode. The only potential structural failure mode within the tubesheet is a circumferential failure mode, leading to tube severance.

The proposed IARC would permit tubes with up to 100 percent through-wall flaws in the portion of the tube from 17 inches below the TTS to 1 inch above the bottom of the tubesheet to remain in service provided the circumferential component of these flaws does not exceed 203 degrees. The 203-degree criterion was determined on the basis of the remaining cross-sectional area of the tube needed to resist the limiting axial end-cap load on the tube and the pressure load on the flaw cross-section, using limit-load analysis, with safety factors consistent with those required by the performance criteria for structural integrity in TS. Because the 203-degree criterion was determined on this basis, the NRC staff finds this approach acceptable.

For the portion of the tube from the bottom of the tubesheet to 1 inch above the bottom of the tubesheet, the proposed IARC would permit tubes with up to 100 percent through-wall flaws to remain in service provided the circumferential component of these flaws does not exceed 94 degrees. This criterion is based on the minimum tube-to-tubesheet weld cross-sectional area needed to resist the limiting axial end-cap load on the tube and the pressure load on the flaw cross-section, using limit load analysis, with safety factors consistent with those required by the performance criteria for structural integrity in TS Section 6.8.4.g, "Steam Generator Program". A 203-degree crack in the tube wall immediately above the weld could potentially concentrate the entire end cap load to a 157-degree segment of the weld, whereas a minimum 266 degree segment (i.e., 360 minus 94 degrees) of weld is needed to resist the end-cap load with adequate safety margin. Thus, the 94-degree criterion for the tube in the lowermost 1-inch region is intended to ensure that the weld is not overstressed. The NRC staff reviewed the results of the stress analysis of the weld, which was performed to demonstrate that the weld complied with the stress limits of the ASME Code, Section III. TS Section 6.8.4.g performance criteria for tube structural integrity are intended to ensure safety margins consistent with the ASME Code, Section III stress limits. Based on a comparison of the calculated maximum design stress to the ASME Code-allowable stress, the NRC staff concludes that the proposed 94-degree criterion ensures that the weld can carry the end-cap loads with margins to failure consistent with the margins ensured by the ASME stress limits and is, therefore, acceptable.

The 203- and 94-degree criteria include an allowance for incremental flaw growth in the circumferential direction prior to the next inspection. The licensee states that no significant growth rate data exist for the specific case of circumferential cracking in the tubesheet expansion region. The licensee's growth rate estimate is based on a 95 percent upper bound value of available primary water stress corrosion crack (PWSCC) growth rate data for other tube locations. Given the lack of actual growth rate data for cracks that may potentially initiate in the lowermost 4 inches of the tube, the NRC staff attaches only a low level of confidence in the conservatism of the licensee's growth rate estimate. However, the NRC staff notes that the effect of any lack of conservatism in the licensee's estimate is mitigated by the fact that all of the SGs at MPS3 will be inspected at 3R13, should any crack indications be found during 3R12. In addition, the 203- and 94-degree criteria conservatively take no credit for the effects of friction between the tube and tubesheet in any portion of the tube-to-tubesheet joint, in reacting out a portion of the axial end cap load before it reaches the cracked cross-section. Thus, the NRC staff concludes that the 203- and 94-degree criteria meet the requirements of TS Section 6.8.4.g, irrespective of growth rate uncertainties.

The 203- and 94-degree criteria do not include an explicit allowance for eddy current measurement error. The licensee will be utilizing an inspection technique that has been qualified for the detection of circumferential PWSCC in tube expansion transitions and in the tack expansion region just above the tube to tubesheet weld. The tack expansion is an approximately 1-inch long expansion of the tube in the tubesheet that is performed before the tube is hydraulically expanded for the entire depth of the tubesheet. DNC states that a fundamental assumption behind the proposed 203- and 94-degree repair criteria is that all detected circumferential flaws in the lowermost 4 inches of the tube are fully 100% through wall, irrespective of the actual depth of the flaw. With this assumption, the licensee referenced an Electric Power Research Institute (EPRI) sponsored study that indicated the eddy current measurement of the crack arc length was conservative (i.e., larger than the actual crack size), and resulted in an estimate of the remaining cross sectional area that was always smaller than values obtained through direct measurement of cracks. The NRC staff finds, based on the results of the study, that any uncertainties relating to measured arc length of the flaw are not expected to prevent the 203- and 94-degree criteria from meeting the requirements of TS Section 6.8.4.g.

The proposed IARC also includes criteria to account for interaction effects for multiple circumferential flaws that are in close proximity. The proposed criteria treat the multiple circumferential flaws located within 1 inch of one another as all occurring at the same axial location. The total arc length of the combined flaw is the sum of the individual flaw arc lengths with overlapping arc lengths counted only once. The licensee stated that the summation of cracks with both located more than 17 inches from the TTS and more than 1 inch from the bottom of the tube will be compared to the 203-degree criterion. The summation of cracks with one flaw located less than 1 inch from the bottom of the tubesheet and the other within 1 inch of the first (or both flaws within 1 inch of the bottom of the tubesheet) would be compared to the 94-degree criterion. Cracks located more than 1 inch apart are assumed to act independently of each other. This 1-inch criterion was determined using a fracture mechanics approach to determine the axial distance from an individual crack tip at which the stress distribution reverts to a nominal stress distribution for an uncracked section. The 1-inch criterion is twice the calculated distance since twice this distance is the necessary separation between two cracks for the cracks to act independently of each other. The NRC staff reviewed the basis for the 1-inch criterion and the fracture mechanics approach to determining the criterion and finds it acceptable.

The proposed IARC would permit tubes with axial cracks in the lowermost 4 inches of the tube to remain in service, irrespective of crack depth. The NRC staff finds this acceptable because axial cracks do not impair the ability of the tube or the weld to resist axial load and because the tube is fully constrained by the tubesheet against an axial failure mode.

Finally, the proposed IARC includes a requirement to plug all tubes in which flaws are detected in the upper 17-inch portion of the tube within the tubesheet. This adds to the conservatism of the 203- and 94-degree criteria since it mitigates any loss of tightness and, thus, any loss of friction between the tube and tubesheet due to flaws in the upper 17-inch region of the joint.

4.2.1.2 Accident Leakage Integrity Considerations

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. Operational leakage integrity is assured by monitoring primary-to-secondary leakage relative to the applicable TS LCO limits in TS 3/4.4.6, "Reactor Coolant System Leakage." However, it must also be demonstrated that the proposed TS changes do not create the potential for leakage during DBAs 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. The licensee states that this is ensured for MPS by limiting primary-to-secondary leakage to 0.35 gallon per minute in the faulted SG during an MSLB accident.

The leakage path between the tube and tubesheet was 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. Westinghouse stated that the flow resistance varied as a log normal linear function of joint contact pressure, but due to the large scatter of the flow resistance test data, contact pressure was assumed to be constant with joint contact pressure at a value which conservatively lower bounded the data.

The proposed leakage model relies on an assumed, constant value of loss coefficient, based on a lower bound of the data. The NRC staff was not able to conclude that the assumed value of loss coefficient in the model was conservative. Instead, the NRC staff has performed some evaluations regarding the potential for the normal operating leak rate to increase under steam-line break conditions. Making the conservative assumption that loss coefficient and viscosity are constant under both normal operating and steam-line break conditions, the ratio of steam-line break leakage rate to normal operating leak rate is equal to the ratio of steam-line break differential pressure to normal operating differential pressure times the ratio of effective crevice length under normal operating conditions (l_{NOP}) to effective crevice length under steam-line break conditions (l_{SLB}). Effective crevice length is the crevice length over which there is contact between the tube and tubesheet. Using various values of (l_{NOP}/ l_{SLB}) determined from tubesheet analyses docketed for other similar plants, the NRC staff concluded that a factor of 2.5 reasonably bounded the potential increase in leakage from the lowermost 4 inches of tubing that would be realized in going from normal operating to steam-line break conditions.

The licensee provided a regulatory commitment in its May 8, 2008, letter stating that it would apply the 2.5 factor in its condition monitoring (CM) and operational assessment (OA) upon implementation of the subject license amendment. Specifically, for the CM assessment, the licensee states that the component of leakage from the lowermost 4 inches for the most limiting SG during the prior cycle of operation will be multiplied by a factor of 2.5 and added to the total leakage from any other source and compared to the allowable accident leakage limit. For the OA, the licensee stated that the difference in leakage from the allowable accident leakage limit and the accident leakage from other sources will be divided by 2.5 and compared to the observed (operational) leakage and that an administrative limit (for operational leakage) will be established to not exceed the calculated value.

The NRC previously found that NEI 99-04, Revision 0, provides reasonable guidance for the control of regulatory commitments made to the NRC staff (Regulatory Issue Summary 2000-17, "Managing Regulatory Commitments Made by Power Reactor Licensees to the NRC Staff," dated September 21, 2000). These commitments will be controlled in accordance with the licensee's commitment management program in accordance with NEI 99-04. Any change to the regulatory commitments is subject to licensee management approval and subject to the procedural controls established at the plant for commitment management in accordance with NEI 99-04, which include notification of the NRC. Also, the NRC staff may choose to verify the implementation and maintenance of these commitments in a future inspection or audit.

Based on this, the NRC staff concludes that the regulatory commitment addressed above for this amendment is acceptable.

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

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

4.3 <u>Summary</u>

Based on the above evaluation, the NRC staff finds that the proposed license amendment, which is applicable only to 3R12 and the subsequent operating cycle, ensures that SG tube structural and leakage integrity will be maintained during this period with structural safety margins consistent with the design basis and with leakage integrity within assumptions employed in the licensing basis accident analyses, and will have no adverse impact on the ability of the tube-to-tubesheet welds to perform their safety-related function. Based on this finding, the NRC staff further concludes that the proposed amendment meets 10 CFR 50.36 and, thus, the proposed amendment is acceptable.

The current TSs and the proposed amendment do not address inspection requirements for the tube-to-tubesheet welds. There are no safety issues with respect to hypothetical cracks in the weld because it can be demonstrated, such as with the H*/B* strategies discussed in Section 4 of this safety evaluation, that the axial end-cap loads in the tube are reacted by frictional forces developed between the tube and tubesheet before any portion of the end-cap load is transmitted to the weld

5.0 <u>STATE CONSULTATION</u>

In accordance with the Commission's regulations, the Connecticut State official was notified of the proposed issuance of the amendment. The State official's comments have been addressed in this SE.

6.0 <u>ENVIRONMENTAL CONSIDERATION</u>

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 (73 FR 39054). 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.

Principal Contributor: Andrew Johnson

Date: September 30, 2008

September 30, 2008

Mr. David A. Christian
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 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" (TAC NO. MD8736)

Dear Mr. Christian:

The Nuclear Regulatory Commission has issued the enclosed Amendment No. 245 to Renewed Facility Operating License No. NPF-49 for the Millstone Power Station, Unit No. 3, in response to your application dated May 8, 2008 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML081490087).

The amendment changes the repair requirements of Technical Specification (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 proposed changes would establish alternate repair criteria for portions of the SG tubes within the tubesheet, and would be applicable to Millstone Power Station, Unit 3 No. during Refueling Outage 12 and the subsequent operating cycle only.

A copy of the related 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. 245 to NPF-49
2. Safety Evaluation

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