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

October 16, 2009

Mr. Charles G. Pardee
President and Chief Nuclear Officer
Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: BRAIDWOOD STATION, UNITS 1 AND 2, AND BYRON STATION, UNIT NOS. 1 AND 2 - ISSUANCE OF AMENDMENTS RE: REVISION TO TECHNICAL SPECIFICATIONS FOR THE STEAM GENERATOR PROGRAM (TAC NOS. ME1613, ME1614, ME1615, AND ME1616)

Dear Mr. Pardee:

The Nuclear Regulatory Commission (the Commission) has issued the enclosed Amendment No.161 to Facility Operating License No. NPF- 72 and Amendment No.161 to Facility Operating License No. NPF-77 for the Braidwood Station (Braidwood), Units 1 and 2, and Amendment No.166 to Facility Operating License No. NPF-37 and Amendment No.166 to Facility Operating License No. NPF-66 for the Byron Station (Byron), Unit Nos. 1 and 2, respectively. The amendments are in response to your application dated June 24, 2009 (Agencywide Documents Access and Management System (ADAMS) Package No. ML091770543), as supplemented by letters dated August 14, August 31, and September 15, 2009 (ADAMS Package Nos. ML092320375, ML092460588, and ML092600168, respectively).

The amendments revise Technical Specification (TS) 5.5.9, "Steam Generator (SG) Program," to exclude portions of the tube below the top of the SG tubesheet from periodic SG tube inspections and plugging or repair. In addition, the amendments revise the wording of reporting requirements in TS 5.6.9, "Steam Generator (SG) Tube Inspection Report." These changes only affect Braidwood, Unit 2, and Byron, Unit No. 2; however, this action is docketed for both Braidwood and Byron units because the Braidwood TS are common to both Braidwood units, and the Byron TS are common to both Byron units. The letter dated September 15, 2009, revised the proposed changes to the TS in the June 24, 2009, letter, to be applicable to Braidwood, Unit 2, during refueling outage (RFO) 14 (fall 2009) and the subsequent operating cycle, and to Byron, Unit No. 2, during RFO 15 (spring 2010) and the subsequent operating cycle.

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

Sincerely,

Marshall J. David, Senior Project Manager
Plant Licensing Branch III-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. STN 50-456, STN 50-457,
STN 50-454, and STN 50-455

Enclosures:
1. Amendment No. 161 to NPF-72
2. Amendment No. 161 to NPF-77
3. Amendment No. 166 to NPF-37
4. Amendment No. 166 to NPF-66
5. Safety Evaluation

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

EXELON GENERATION COMPANY, LLC

DOCKET NO. STN 50-456

BRAIDWOOD STATION, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 161
License No. NPF-72

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

   A. The application for amendment by Exelon Generation Company, LLC (the licensee) dated June 24, 2009, as supplemented by letters dated August 14, August 31, and September 15, 2009, 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 Facility Operating License No. NPF-72 is hereby amended to read as follows:

(2) Technical Specifications

The Technical Specifications contained in Appendix A as revised through Amendment No.161, and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto, are hereby incorporated into this license. The licensee 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 its issuance and shall be implemented within 30 days of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Christopher Gratton for

Stephen J. Campbell, Chief
Plant Licensing Branch III-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications and Facility Operating License

Date of Issuance: October 16, 2009

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

EXELON GENERATION COMPANY, LLC

DOCKET NO. STN 50-457

BRAIDWOOD STATION, UNIT 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 161
License No. NPF-77

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

   A. The application for amendment by Exelon Generation Company, LLC (the licensee) dated June 24, 2009, as supplemented by letters dated August 14, August 31, and September 15, 2009, 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 Facility Operating License No. NPF-77 is hereby amended to read as follows:

(2) Technical Specifications

The Technical Specifications contained in Appendix A as revised through Amendment No. 161, and the Environmental Protection Plan contained in Appendix B, both of which are attached to License No. NPF-72, dated July 2, 1987, are hereby incorporated into this license. The licensee 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 its issuance and shall be implemented within 30 days of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Christopher Gratton for

Stephen J. Campbell, Chief
Plant Licensing Branch III-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications and Facility Operating License

Date of Issuance: October 16, 2009

ATTACHMENT TO LICENSE AMENDMENT NOS. 161 AND 161

FACILITY OPERATING LICENSE NOS. NPF-72 AND NPF-77

DOCKET NOS. STN 50-456 AND STN 50-457

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

Remove	Insert
License NPF-72	License NPF-72
License Page 3	License Page 3
License NPF-77	License NPF-77
License Page 3	License Page 3
TSs	TSs
5.5-8	5.5-8
5.5-9	5.5-9
5.5-10	5.5-10
5.5-11	5.5-11
5.6-6	5.6-6
5.6-7	5.6-7

(3) Exelon Generation Company, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use at any time any byproduct, source and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) Exelon Generation Company, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(5) Exelon Generation Company, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. The license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

The licensee is authorized to operate the facility at reactor core power levels not in excess of 3586.6 megawatts thermal (100 percent rated power) in accordance with the conditions specified herein and other items identified in Attachment 1 to this license. The items identified in Attachment 1 to this license shall be completed as specified. Attachment 1 is hereby incorporated into this license.

(2) Technical Specifications

The Technical Specifications contained in Appendix A as revised through Amendment No.161, and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto, are hereby incorporated into this license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) Emergency Planning

In the event that the NRC finds that the lack of progress in completion of the procedures in the Federal Emergency Management Agency's final rule, 44 CFR Part 350, is an indication that a major substantive problem exists in achieving or maintaining an adequate state of emergency preparedness, the provisions of 10 CFR Section 50.54(s)(2) will apply.

material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) Exelon Generation Company, LLC pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use in amounts are required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(5) Exelon Generation Company, LLC, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. The license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

The licensee is authorized to operate the facility at reactor core power levels not in excess of 3586.6 megawatts thermal (100 percent rated power) in accordance with the conditions specified herein and other items identified in Attachment 1 to this license. The items identified in Attachment 1 to this license shall be completed as specified. Attachment 1 is hereby incorporated into this license.

(2) Technical Specifications

The Technical Specifications contained in Appendix A as revised through Amendment No.161 , and the Environmental Protection Plan contained in Appendix B, both of which are attached to License No. NPF-72, dated July 2, 1987, are hereby incorporated into this license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) Emergency Planning

In the event that the NRC finds that the lack of progress in completion of the procedures in the Federal Emergency Management Agency's final rule, 44 CFR Part 350, is an indication that a major substantive problem exists in achieving or maintaining an adequate state of emergency preparedness, the provisions of 10 CFR Section 50.54(s)(2) will apply.

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

2. Accident induced leakage performance criterion: The primary to secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed a total of 1 gpm for all SGs.

3. The operational LEAKAGE performance criteria is specified in LCO 3.4.13, "RCS Operational LEAKAGE."

c. Provisions for SG tube repair criteria.

1. Tubes found by inservice inspection to contain flaws in a non-sleeved region with a depth equal to or exceeding 40% of the nominal wall thickness shall be plugged or repaired. The following alternate tube repair criteria shall be applied as an alternative to the 40% depth based criteria:

   For Unit 2 during Refueling Outage 14 and the subsequent operating cycle, tubes with service-induced flaws located greater than 16.95 inches below the top of the tubesheet do not require plugging or repair. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 16.95 inches below the top of the tubesheet shall be plugged or repaired upon detection.

2. Sleeves found by inservice inspection to contain flaws with a depth equal to or exceeding the following percentages of the nominal sleeve wall thickness shall be plugged:

   i. For Unit 2 only, TIG welded sleeves (per TS 5.5.9.f.2.i): 32%

3. Tubes with a flaw in a sleeve to tube joint that occurs in the sleeve or in the original tube wall of the joint shall be plugged.

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (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 Unit 2 during Refueling Outage 14 and the subsequent operating cycle, portions of the tube below 16.95 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 Unit 1 tubes at sequential periods of 144, 108, 72, 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 72 effective full power months or three refueling outages (whichever is less) without being inspected.

   Inspect 100% of the Unit 2 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.

5.5 Programs and Manuals

5.5.9 <u>Steam Generator (SG) Program</u> (continued)

3. For Unit 1, 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). For Unit 2 during Refueling Outage 14 and the subsequent operating cycle, if crack indications are found in any SG tube from 16.95 inches below the top of the tubesheet on the hot leg side to 16.95 inches below the top of the tubesheet on the cold leg side, 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.

f. Provisions for SG tube repair methods. Steam generator tube repair methods shall provide the means to reestablish the RCS pressure boundary integrity of SG tubes without removing the tube from service. For the purposes of these Specifications, tube plugging is not a repair.

   1. There are no approved tube repair methods for the Unit 1 SGs.

   2. All acceptable repair methods for the Unit 2 SGs are listed below.

      i. TIG welded sleeving as described in ABB Combustion Engineering Inc., Technical Reports: Licensing Report CEN-621-P, Revision 00, "Commonwealth Edison Byron and Braidwood Unit 1 and 2 Steam Generators Tube Repair Using Leak Tight Sleeves, FINAL REPORT," April 1995; and Licensing Report CEN-627-P, "Operating Performance of the ABB CENO Steam Generator Tube Sleeve for Use at Commonwealth Edison Byron and Braidwood Units 1 and 2," January 1996; subject to the limitations and restrictions as noted by the NRC Staff.

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5.6 Reporting Requirements

5.6.8 Tendon Surveillance Report

Any abnormal degradation of the containment structure detected during the tests required by the Pre-Stressed Concrete Containment Tendon Surveillance Program shall be reported in the Inservice Inspection Summary Report in accordance with 10 CFR 50.55a and ASME Section XI.

5.6.9 Steam Generator (SG) Tube Inspection Report

A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with Specification 5.5.9, 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 or repaired during the inspection outage for each active degradation mechanism,

f. Total number and percentage of tubes plugged or repaired 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 and tube repairs in each SG,

i. Repair method utilized and the number of tubes repaired by each repair method,

5.6 Reporting Requirements

5.6.9 Steam Generator (SG) Tube Inspection Report (continued)

j. For Unit 2 following completion of an inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle), the operational primary to secondary leakage rate observed (greater than three gallons per day) in each steam generator (if it is not practical to assign the leakage to an individual steam generator, 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. For Unit 2 following completion of an inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle), the calculated accident induced leakage rate from the portion of the tubes below 16.95 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 3.11 times the maximum operational primary to secondary leakage rate, the report should describe how it was determined, and

l. For Unit 2 following completion of an inspection performed in Refueling Outage 14 (and any inspections performed in 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.

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

EXELON GENERATION COMPANY, LLC

DOCKET NO. STN 50-454

BYRON STATION, UNIT NO. 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 166
License No. NPF-37

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

    A. The application for amendment by Exelon Generation Company, LLC (the licensee) dated June 24, 2009, as supplemented by letters dated August 14, August 31, and September 15, 2009, 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 Facility Operating License No. NPF-37 is hereby amended to read as follows:

(2) Technical Specifications

The Technical Specifications contained in Appendix A as revised through Amendment No.166 and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto, are hereby incorporated into this license. The licensee 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 its issuance and shall be implemented prior to conducting the steam generator inspections required by Technical Specification 5.5.9 for the Byron, Unit No. 2, spring 2010 refueling outage (B2R15).

FOR THE NUCLEAR REGULATORY COMMISSION

Christopher Gratton for

Stephen J. Campbell, Chief
Plant Licensing Branch III-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications and Facility Operating License

Date of Issuance: October 16, 2009

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

EXELON GENERATION COMPANY, LLC

DOCKET NO. STN 50-455

BYRON STATION, UNIT NO. 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 166
License No. NPF-66

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

   A. The application for amendment by Exelon Generation Company, LLC (the licensee) dated June 24, 2009, as supplemented by letters dated August 14, August 31, and September 15, 2009, 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 Facility Operating License No. NPF-66 is hereby amended to read as follows:

(2) Technical Specifications

The Technical Specifications contained in Appendix A (NUREG 1113), as revised through Amendment No.166 and the Environmental Protection Plan contained in Appendix B, both of which are attached to License No. NPF-37, dated February 14, 1985, are hereby incorporated into this license. The licensee 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 its issuance and shall be implemented prior to conducting the steam generator inspections required by Technical Specification 5.5.9 for the Byron, Unit No. 2, spring 2010 refueling outage (B2R15).

FOR THE NUCLEAR REGULATORY COMMISSION

Christopher Gratton for

Stephen J. Campbell, Chief
Plant Licensing Branch III-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications and Facility Operating License

Date of Issuance: October 16, 2009

ATTACHMENT TO LICENSE AMENDMENT NOS.166AND 166

FACILITY OPERATING LICENSE NOS. NPF-37 AND NPF-66

DOCKET NOS. STN 50-454 AND STN 50-455

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

Remove	Insert
License NPF-37	License NPF-37
License Page 3	License Page 3
License NPF-66	License NPF-66
License Page 3	License Page 3
TSs	TSs
5.5-8	5.5-8
5.5-9	5.5-9
5.5-10	5.5-10
5.5-11	5.5-11
5.6-6	5.6-6
5.6-7	5.6-7

(4) Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(5) Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. The license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

The licensee is authorized to operate the facility at reactor core power levels not in excess of 3586.6 megawatts thermal (100 percent power) in accordance with the conditions specified herein.

(2) Technical Specifications

The Technical Specifications contained in Appendix A as revised through Amendment No. 166, and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto, are hereby incorporated into this license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) Deleted.

(4) Deleted.

(5) Deleted.

(6) The licensee shall implement and maintain in effect all provisions of the approved fire protection program as described in the licensee's Fire Protection Report, and as approved in the SER dated February 1987 through Supplement No. 8, subject to the following provision:

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

(3) Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use at any time any byproduct, source and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use in amounts are required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(5) Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. The license shall be deemed to contain and is subject to the conditions specified in the Commission's regulation set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

The licensee is authorized to operate the facility at reactor core power levels not in excess of 3586.6 megawatts thermal (100 percent rated power) in accordance with the conditions specified herein.

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A (NUREG 1113), as revised through Amendment No. 166 and the Environmental Protection Plan contained in Appendix B, both of which are attached to License No. NPF-37, dated February 14, 1985, are hereby incorporated into this license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) Deleted.

(4) Deleted.

(5) Deleted.

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

2. Accident induced leakage performance criterion: The primary to secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed a total of 1 gpm for all SGs.

3. The operational LEAKAGE performance criteria is specified in LCO 3.4.13, "RCS Operational LEAKAGE."

c. Provisions for SG tube repair criteria.

1. Tubes found by inservice inspection to contain flaws in a non-sleeved region with a depth equal to or exceeding 40% of the nominal wall thickness shall be plugged or repaired. The following alternate tube repair criteria shall be applied as an alternative to the 40% depth based criteria:

   For Unit 2 during Refueling Outage 15 and the subsequent operating cycle, tubes with service-induced flaws located greater than 16.95 inches below the top of the tubesheet do not require plugging or repair. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 16.95 inches below the top of the tubesheet shall be plugged or repaired upon detection.

2. Sleeves found by inservice inspection to contain flaws with a depth equal to or exceeding the following percentages of the nominal sleeve wall thickness shall be plugged:

   i. For Unit 2 only, TIG welded sleeves (per TS 5.5.9.f.2.i): 32%

3. Tubes with a flaw in a sleeve to tube joint that occurs in the sleeve or in the original tube wall of the joint shall be plugged.

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (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 Unit 2 during Refueling Outage 15 and the subsequent operating cycle, portions of the tube below 16.95 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 Unit 1 tubes at sequential periods of 144, 108, 72, 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 72 effective full power months or three refueling outages (whichever is less) without being inspected.

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

Inspect 100% of the Unit 2 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. For Unit 1, 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). For Unit 2 during Refueling Outage 15 and the subsequent operating cycle, if crack indications are found in any SG tube from 16.95 inches below the top of the tubesheet on the hot leg side to 16.95 inches below the top of the tubesheet on the cold leg side, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less).

If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

e. Provisions for monitoring operational primary to secondary LEAKAGE.

f. Provisions for SG tube repair methods. Steam generator tube repair methods shall provide the means to reestablish the RCS pressure boundary integrity of SG tubes without removing the tube from service. For the purposes of these Specifications, tube plugging is not a repair.

1. There are no approved tube repair methods for the Unit 1 SGs.

2. All acceptable repair methods for the Unit 2 SGs are listed below.

i. TIG welded sleeving as described in ABB Combustion Engineering Inc., Technical Reports: Licensing Report CEN-621-P, Revision 00, "Commonwealth Edison Byron and Braidwood Unit 1 and 2 Steam Generators Tube Repair Using Leak Tight Sleeves, FINAL REPORT," April 1995; and Licensing Report CEN-627-P, "Operating Performance of the ABB CENO Steam Generator Tube Sleeve for Use at Commonwealth Edison Byron and Braidwood Units 1 and 2," January 1996; subject to the limitations and restrictions as noted by the NRC Staff.

5.6 Reporting Requirements

5.6.8 Tendon Surveillance Report

Any abnormal degradation of the containment structure detected during the tests required by the Pre-Stressed Concrete Containment Tendon Surveillance Program shall be reported in the Inservice Inspection Summary Report in accordance with 10 CFR 50.55a and ASME Section XI.

5.6.9 Steam Generator (SG) Tube Inspection Report

A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with Specification 5.5.9, 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 or repaired during the inspection outage for each active degradation mechanism,

f. Total number and percentage of tubes plugged or repaired 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 and tube repairs in each SG, and

i. Repair method utilized and the number of tubes repaired by each repair method.

5.6 Reporting Requirements

5.6.9 Steam Generator (SG) Tube Inspection Report (continued)

j. For Unit 2 following completion of an inspection performed in Refueling Outage 15 (and any inspections performed in the subsequent operating cycle), the operational primary to secondary leakage rate observed (greater than three gallons per day) in each steam generator (if it is not practical to assign the leakage to an individual steam generator, 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. For Unit 2 following completion of an inspection performed in Refueling Outage 15 (and any inspections performed in the subsequent operating cycle), the calculated accident induced leakage rate from the portion of the tubes below 16.95 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 3.11 times the maximum operational primary to secondary leakage rate, the report should describe how it was determined, and

l. For Unit 2 following completion of an inspection performed in Refueling Outage 15 (and any inspections performed in 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.

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO.161 TO FACILITY OPERATING LICENSE NO. NPF-72,

AMENDMENT NO.161 TO FACILITY OPERATING LICENSE NO. NPF-77,

AMENDMENT NO.166 TO FACILITY OPERATING LICENSE NO. NPF-37,

AND AMENDMENT NO.166 TO FACILITY OPERATING LICENSE NO. NPF-66

EXELON GENERATION COMPANY, LLC

BRAIDWOOD STATION, UNITS 1 AND 2

BYRON STATION, UNIT NOS. 1 AND 2

DOCKET NOS. STN 50-456, STN 50-457,

STN 50-454, AND STN 50-455

1.0 INTRODUCTION

By letter dated June 24, 2009 (Reference 1), as supplemented by letters dated August 14 and 31, 2009 (References 2 and 3), Exelon Generation Company, LLC (EGC, the licensee) submitted a license amendment request (LAR) to revise the technical specifications (TS) of Byron Station (Byron), Unit Nos. 1 and 2, and Braidwood Station (Braidwood), Units 1 and 2. The request proposed changes to the inspection scope and plugging or repair requirements of TS 5.5.9, "Steam Generator (SG) Program" and to the reporting requirements of TS 5.6.9, "Steam Generator (SG) Tube Inspection Report." The proposed changes would be applicable only to Braidwood, Unit 2, and Byron, Unit No. 2, and would establish permanent alternate repair criteria for portions of the SG tubes within the tubesheet.

The June 24, 2009, letter provided information to be used for establishing a technical basis for implementing the proposed license amendments. The August 14 and 31, 2009, letters provided additional information in response to requests for additional information (RAIs) from the Nuclear Regulatory Commission (NRC) staff. Because of an unresolved technical issue in the RAI responses, the licensee submitted a letter dated September 15, 2009 (Reference 4), which requested that the changes proposed in the June 24, 2009, LAR be applicable for one cycle only, specifically, for Braidwood, Unit 2, during Refueling Outage 14 (fall 2009) and the subsequent operating cycle, and for Byron, Unit No. 2, during Refueling Outage 15 (spring 2010) and the subsequent operating cycle.

The supplemental letters, provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change NRC staff's original proposed no significant hazards consideration determination published in an individual notice in the *Federal Register* on July 31, 2009 (74 FR 38234).

2.0 BACKGROUND

Braidwood, Unit 2, and Byron, Unit No. 2, have four Model D5 SGs each, which were designed and fabricated by Westinghouse. There are 4,570 Alloy 600 tubes in each SG, each with an outside diameter of 0.750 inches and a nominal wall thickness of 0.043 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 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 Braidwood, Unit 2, and Byron, Unit No. 2, the Catawba SGs use thermally-treated Alloy 600 tubing that is hydraulically-expanded against the tubesheet. The crack-like indications at Catawba were found in a tube over expansion, in the tack expansion region, and near the tube-to-tubesheet (T/TS) weld. An over expansion is created when the tube is expanded into a tubesheet bore hole that is not perfectly round. These out-of-round conditions were created during the tubesheet drilling process by conditions such as drill bit wandering or chip gouging. The tack expansion is an approximately 1-inch long expansion at each tube end. The purpose of the tack expansion is to facilitate performing the T/TS weld, which is made prior to the hydraulic expansion of the tube over the full tubesheet depth.

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

On February 21, 2006, Wolf Creek Nuclear Operating Corporation (WCNOC), the licensee for Wolf Creek Generating Station, submitted a LAR that would permanently limit the scope of inspections required for tubes within the tubesheet (Reference 5). The LAR was based on an analysis performed by Westinghouse that provided a technical basis for permanently limiting the scope of inspections required for tubes within the tubesheet. After three RAIs and several meetings with WCNOC, the NRC staff informed WCNOC during a phone call on January 3, 2008, that it had not provided sufficient information to allow the NRC staff to review and approve the permanent LAR. WCNOC withdrew the LAR by letter dated February 14, 2008 (Reference 6). In a letter dated February 8, 2008 (Reference 7), the NRC staff identified the specific issues that needed to be addressed to support any future request for a permanent amendment, which included but were not limited to thermal expansion coefficients, crevice pressure assumptions, uncertainty models, acceptance standards for probabilistic assessment, and leakage resistance.

The Vogtle licensee had also submitted a permanent LAR (Reference 8), that used the same technical basis as the WCNOC LAR. Upon learning of the NRC staff's concerns with the WCNOC permanent LAR, the Vogtle licensee modified its permanent LAR by letter dated February 13, 2008 (Reference 9), with one-cycle LARs that used a conservative interim alternate repair criteria (IARC) approach. The NRC staff sent additional RAIs related to the IARC and the

Vogtle licensee responded satisfactorily. The IARCs for Vogtle Units 1 and Unit 2 were thus approved by the NRC staff on April 9, 2008 (Reference 10), and September 16, 2008 (Reference 11).

After Vogtle received approval of the IARC amendments, several licensees submitted and gained approval for one-cycle IARC amendments that used the more conservative approach. Byron, Unit No. 2, and Braidwood, Unit 2, currently have approved one-cycle IARC amendments.

After withdrawal of the initial round of permanent LARs submitted prior to 2008, the licensees and their contractor, Westinghouse, worked with the NRC staff to address the issues posed in Reference 7. The NRC staff and industry held public meetings (References 12, 13, and 14) and phone calls to discuss resolution of these issues. The permanent LAR received from Braidwood, Unit 2, and Byron, Unit No. 2, in 2009 (Reference 1), resolved the issues identified by the NRC staff in Reference 7, but raised an additional technical issue, as discussed in Section 4.3.1.3. For this reason, the licensee modified its LAR to apply during Braidwood, Unit 2, during Refueling Outage 14 (fall 2009), and the subsequent operating cycle, and to Byron, Unit No. 2, during Refueling Outage 15 (spring 2010), and the subsequent operating cycle, instead of the permanent change originally requested.

3.0 REGULATORY EVALUATION

In Title 10 of the *Code of Federal Regulations* (10 CFR) 50.36, "Technical specifications," the requirements related to the content of the TS are established. Pursuant to 10 CFR 50.36, TS are required to include items in the following five 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 TS. In 10 CFR 50.36(c)(5), Administrative controls are, "the provisions relating to organization and management, procedures, recordkeeping, review and audit, and reporting necessary to assure the operation of the facility in a safe manner." Programs established by the licensee, including the SG program, are listed in the administrative controls section of the TS to operate the facility in a safe manner. For Braidwood, Unit 2, and Byron, Unit No. 2, the requirements for performing SG tube inspections and repair are in TS 5.5.9, while the requirements for reporting the SG tube inspections and repair are in TS 5.6.9.

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 Braidwood, Unit 2, and Byron, Unit No. 2, SG tube integrity is maintained by meeting the performance criteria specified in TS 5.5.9.b for structural and leakage integrity, consistent with the plant design and licensing basis. TS 5.5.9.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 5.5.9.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, and that may satisfy the applicable tube repair criteria. The applicable tube repair criteria, specified in TS 5.5.9.c., are that tubes found during inservice inspection to contain flaws with a depth equal to or exceeding 40 percent of the nominal wall thickness shall be plugged or repaired, unless the tubes are permitted to remain in service through application of the proposed alternate repair criteria provided in TS 5.5.9.c.1.

The SG tubes are part of the reactor coolant pressure boundary (RCPB) and isolate fission products in the primary coolant from the secondary coolant. For the purposes of this safety evaluation, SG tube integrity means that the tubes are capable of performing this safety function in accordance with the plant design and licensing basis. The General Design Criteria (GDC) in Appendix A to 10 CFR Part 50 provide regulatory requirements, which are applicable to Braidwood, Unit 2, and Byron, Unit No. 2, and state that the RCPB shall have "an extremely low probability of abnormal leakage…and of gross rupture" (GDC 14), "shall be designed with sufficient margin" (GDC 15 and 31), shall be of "the highest quality standards practical" (GDC 30), and shall be designed to permit "periodic inspection and testing…to assess…structural and leaktight integrity" (GDC 32). The licensee discusses compliance with each of these GDC for Braidwood, Unit 2, and Byron, Unit No. 2, in Section 3.1 of the Updated Final Safety Analysis Report (UFSAR) and does not identify any deviation from these GDC for SG tube-related issues. To this end, 10 CFR 50.55a specifies that components, which are part of the RCPB, must meet the requirements for Class 1 components in Section III of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), except as provided in 10 CFR 50.55a(c)(2), (3), and (4). Section 50.55a further requires that throughout the service life of PWR facilities (like Braidwood and Byron), ASME Code Class 1 components meet the Section XI requirements of the ASME Code to the extent practical, except for design and access provisions, and pre-service examination requirements. This requirement includes the inspection and repair criteria of Section XI of the ASME Code. The Section XI requirements pertaining to in-service inspection of SG tubing are augmented by additional requirements in the TS.

As part of the plant's licensing bases, applicants for PWR licenses are required to analyze the consequences of postulated design-basis accidents (DBAs), such as a SG tube rupture and a main steamline break (MSLB). These analyses consider primary-to-secondary leakage that may occur during these events, and must show that the offsite radiological consequences do not exceed the applicable limits of the 10 CFR 50.67, "Accident source term," GDC 19 for control room operator doses (or some fraction thereof as appropriate to the accident), or the NRC-approved licensing basis (e.g., a small fraction of these limits). No accident analyses for Braidwood, Unit 2, and Byron, Unit No. 2, are being changed because of the proposed amendments and, thus, no radiological consequences of any accident analysis are being changed. The use of the proposed alternate repair criteria does not impact the integrity of the SG tubes, and the SG tubes, therefore, still meet the requirements of the GDCs in Appendix A to 10 CFR Part 50, and the requirements for Class 1 components in Section III of the ASME Code. The proposed changes maintain the accident analyses and consequences that the NRC staff reviewed and approved for the postulated DBAs for SG tubes.

The proposed amendments eliminate inspection and plugging or repair of tubes more than 16.95 inches below the top of the tubesheet (TTS). Tubes with service-induced flaws located in the portion of the tube from the TTS to 16.95 inches below the TTS shall be plugged or repaired upon detection. The proposed amendments would be applicable to Braidwood, Unit 2, during Refueling Outage 14 (fall 2009), and the subsequent operating cycle, and to Byron, Unit No. 2, during Refueling Outage 15 (spring 2010), and the subsequent operating cycle.

4.0 TECHNICAL EVALUATION

4.1 Proposed Changes to the TS – Braidwood, Unit 2,

TS 5.5.9. is being revised as follows (new text in **bold**):

5.5.9 Steam Generator (SG) Program

c. Provisions for SG tube repair criteria.

1. Tubes found by inservice inspection to contain flaws in a non-sleeved region with a depth equal to or exceeding 40% of the nominal wall thickness shall be plugged or repaired. **The following alternate tube repair criteria shall be applied as an alternative to the 40% depth based criteria:**

   For Unit 2 during Refueling Outage 14 and the subsequent operating cycle, tubes with service-induced flaws located greater than 16.95 inches below the top of the tubesheet do not require plugging or repair. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 16.95 inches below the top of the tubesheet shall be plugged or repaired upon detection.

2. [No change/Not shown]

3. [No change/Not shown]

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 Unit 2 during Refueling Outage 14 and the subsequent operating cycle, portions of the tube below 16.95 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. **For Unit 1, 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). **For Unit 2 during Refueling Outage 14 and the subsequent operating cycle, if crack indications are found in any SG tube from 16.95 inches below the top of the tubesheet on the hot leg side to 16.95 inches below the top of the tubesheet on the cold leg side, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less).**

   If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

TS 5.6.9. is being revised as follows (new text in **bold**):

5.6.9 Steam Generator (SG) Tube Inspection Report

A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with Specification 5.5.9, Steam Generator (SG) Program. The report shall include:

a. – i. [No change/Not shown]

j. For Unit 2 following completion of an inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle), the operational primary to secondary leakage rate observed (greater than three gallons per day) in each steam generator (if it is not practical to assign the leakage to an individual steam generator, 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. For Unit 2 following completion of an inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle), the calculated accident induced leakage rate from the portion of the tubes below 16.95 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 3.11 times the maximum operational primary to secondary leakage rate, the report should describe how it was determined, and

l. For Unit 2 following completion of an inspection performed in Refueling Outage 14 (and any inspections performed in 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 Proposed Changes to the TS – Byron, Unit No. 2,

TS 5.5.9. is being revised as follows (new text in **bold**):

5.5.9 Steam Generator (SG) Program

c. Provisions for SG tube repair criteria.

1. Tubes found by inservice inspection to contain flaws in a non-sleeved region with a depth equal to or exceeding 40% of the nominal wall thickness shall be plugged or repaired. **The following alternate tube repair criteria shall be applied as an alternative to the 40% depth based criteria:**

   For Unit 2 during Refueling Outage 15 and the subsequent operating cycle, tubes with service-induced flaws located greater than 16.95 inches below the top of the tubesheet do not require plugging or repair. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 16.95 inches below the top of the tubesheet shall be plugged or repaired upon detection.
2. [No change/Not shown]

3. [No change/Not shown]

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 Unit 2 during Refueling Outage 15 and the subsequent operating cycle, portions of the tube below 16.95 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. **For Unit 1, 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). **For Unit 2 during Refueling Outage 15 and the subsequent operating cycle, if crack indications are found in any SG tube from 16.95 inches below the top of the tubesheet on the hot leg side to 16.95 inches below the top of the tubesheet on the cold leg side, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less).**

   If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

TS 5.6.9. is being revised as follows (new text in **bold**):

5.6.9 Steam Generator (SG) Tube Inspection Report

A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with Specification 5.5.9, Steam Generator (SG) Program. The report shall include:

a. – i. [No change/Not shown]

j. **For Unit 2 following completion of an inspection performed in Refueling Outage 15 (and any inspections performed in the subsequent operating cycle),** the operational primary to secondary leakage rate observed (greater than three gallons per day) in each steam generator (if it is not practical to assign the leakage to an individual steam generator, 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. **For Unit 2 following completion of an inspection performed in Refueling Outage 15 (and any inspections performed in the subsequent operating cycle), the calculated accident induced leakage rate from the portion of the tubes below 16.95 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 3.11 times the maximum operational primary to secondary leakage rate, the report should describe how it was determined, and**

l. **For Unit 2 following completion of an inspection performed in Refueling Outage 15 (and any inspections performed in 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.

4.3 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 reacting the tube end cap loads. The initial hydraulic expansion of the tubes against the tubesheet produces an "interference fit" between the tubes and the tubesheet, thus producing a residual contact pressure (RCP) between the tubes and tubesheet, which acts normally to the outer surface of the tubes and the inner surface of the tubesheet bore holes. Additional contact pressure between the tubes and tubesheet is induced by operational conditions as will be discussed in detail below. The amount of friction force that can be developed between the outer tube surface and the inner surface of the tubesheet bore is a direct function of the contact pressure between the tube and tubesheet times the applicable coefficient of friction.

To support the proposed TS changes, the licensee's contractor, Westinghouse, has defined a parameter called H* to be that distance below the top of the tubesheet over which sufficient frictional force, with acceptable safety margins, can be developed between each tube and the tubesheet under tube end cap pressure loads associated with normal operating and DBA conditions to prevent significant slippage or pullout of the tube from the tubesheet, assuming the tube is fully severed at the H* distance below the top of the tubesheet. For Braidwood, Unit 2, and Byron, Unit No. 2, the proposed H* distance is 16.95 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 plugging and repair criteria. Under these changes, the T/TS joint would now be treated as a friction joint extending from the top of the tubesheet to a distance below the top of the tubesheet equal to H* for purposes of evaluating the structural and leakage integrity of the joint.

The regulatory standard by which the NRC staff has evaluated the subject LAR 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 5.5.9.b.1 discussed in Section 4.3.1.1. 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

5.5.9.b.2, which are consistent with values assumed in the UFSAR accident analyses. Maintaining tube integrity in this manner ensures that the amended TS are in compliance with all applicable regulations. The NRC staff's evaluation of joint structural integrity and accident-induced leakage integrity are discussed in Sections 4.3.1 and 4.3.2, respectively.

4.3.1 Joint Structural Integrity

4.3.1.1 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 that could produce pullout derives from the pressure end cap loads due to the primary-to-secondary pressure differentials associated with normal operating and DBA conditions. Westinghouse determined the needed H* distance on the basis of maintaining a factor of 3 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 5.5.9.b.1 and with the design basis including the stress limit criteria in the ASME Code, Section III.

4.3.1.2 T/TS Interaction Model

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

The shell model representing the tube was used to determine the relationship between the tube outer surface radial displacement and the applied axial end cap load (due to the primary-to-secondary pressure differential), primary pressure acting on the tube inner surface, crevice pressure[1] acting on the tube outer surface, contact pressure between the tube and tubesheet bore, and tube thermal expansion. However, the equivalent shell model representing the tubesheet was used only to determine the relationship between the tubesheet bore surface radial displacement with the applied crevice pressure and contact pressure. Radial displacements of the tubesheet bore surfaces are also functions of the primary pressure acting on the primary face of the tubesheet and SG channel head, secondary pressure acting on the secondary face of the tubesheet and SG shell, and the temperature distribution throughout the entire lower SG assembly. These displacements are a function of tube location within the tube bundle and, also, a function of axial location within the tubesheet. To calculate these displacements, 3-D finite element analyses were performed. The NRC staff's evaluation of these finite element analyses is provided in Section 4.3.1.3. 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 15) assumes as an initial condition that each tube is fully expanded against the tubesheet bore such that the outer tube surface is in contact with the inner surface of the tubesheet bore under room temperature, atmospheric pressure conditions, with zero RCP associated with the hydraulic expansion process. The NRC staff finds the assumption of zero RCP in the reference analysis to be a very conservative assumption.

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

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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 4.3.1.4 for more information.

The resisting force to the applied end cap load, which is developed over each incremental axial distance from the top of the tubesheet, is the average contact pressure over that incremental distance times the tubesheet bore surface area (equal to the tube outer diameter surface area) over the incremental axial distance times the coefficient of friction. The NRC staff reviewed the coefficient of friction used in the analysis and judges it to be a reasonable lower bound (conservative) estimate. The H* distance for each tube was determined by integrating the incremental friction forces from the top of the tubesheet to the distance below the top of the tubesheet where the friction force integral equaled the applied end cap load times the appropriate safety factor as discussed in Section 4.3.1.1.

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.

4.3.1.3 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-leg 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 15, Westinghouse identified a difficultly in applying this relationship to Model D5 SGs for the case of MSLB. Westinghouse attributes this difficulty to the relatively low primary water temperature that exists in Model D5 SGs under MSLB conditions, which is less than the range of temperature that the eccentricity relationship is intended to address. To address this problem, Westinghouse developed an alternative model for the eccentricity effect, which it applied to the Model D5 MSLB case, but continued to apply the original eccentricity relationship for the Model D5 normal operating conditions case. In reviewing the reasons for the problem reported by Westinghouse, the NRC staff developed questions relating to the conservatism of both the original and new eccentricity models and whether the tubesheet bore displacement eccentricities are sufficiently limited such as to ensure that T/TS contact is maintained around the entire tube circumference. However, responses to NRC staff RAIs provided in Reference 3 did not provide sufficient information to allow the NRC staff to reach a conclusion on these matters. The licensee, therefore, modified its LAR on September 15, 2009 (Reference 4), from permanent H* amendments to interim H* amendments applicable to Braidwood, Unit 2, during Refueling Outage 14 (fall 2009), and the subsequent operating cycle, and to Byron, Unit No. 2, during Refueling Outage 15 (spring 2010), and the subsequent operating cycle. Section 4.3.4 provides the NRC staff's evaluation of the interim H* amendment request in light of the open issue relating to tubesheet bore displacement eccentricity. As described in Section 4.3.4, there is sufficient information to enable the NRC staff to evaluate the proposed one-cycle change.

This 3-D finite element analysis replaces the 2-D axisymmetric finite element analyses used to support H* amendment requests submitted prior to 2008. The NRC staff finds that the 3-D analysis adequately addresses a concern cited by the NRC staff in Reference 7 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-leg and cold-leg sides, and the divider plate which acts to connect the solid part of the tubesheet to the channel head.

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

Separate 3-D finite element analyses were conducted for each loading condition considered (i.e., normal operating conditions, MSLB, feedwater line break (FLB)). The NRC staff finds that this adequately addresses (corrects) a significant source of error in analyses used by applicants to support permanent H* amendment requests submitted prior to 2008 and which were subsequently withdrawn (e.g., Reference 7).

4.3.1.4 <u>Crevice Pressure Evaluation</u>

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

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

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

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

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

4.3.1.5 H* Calculation Process

The calculation of H* in the reference analyses (Reference 15) consisted of the following steps for each loading case considered:

1. Perform an 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 a 0.3-inch adjustment to the initial H* estimate to account for uncertainty in the bottom of the tube expansion transition (BET) location relative to the top of the tubesheet, based on an uncertainty analysis on the BET conducted by Westinghouse.

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 4.3.1.7, 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 4.3.1.7 of this safety evaluation. Regarding Step 2, the NRC staff did not review the Westinghouse BET uncertainty analysis. Therefore, at the NRC staff's request, the licensee has committed to a one-time inspection of the actual BET locations during Refueling Outage 14 for Braidwood, Unit 2, (fall 2009), and during Refueling Outage 15 for Byron, Unit No. 2, (spring 2010), to confirm that there are no significant deviations from the assumed BET value. Any such deviations will be entered into the corrective actions program for disposition. The NRC staff finds this to be acceptable, since the BET inspections are a one-time action that is reviewable during routine NRC regional oversight activities. Any deviations are likely to be small (less than a few tenths of an inch), and not likely to impact the overall conservatism of the proposed H* distance.

4.3.1.6 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 4.3.1.1, 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, "Voltage Based Alternate Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside Diameter Stress Corrosion Cracking" (Reference 16), 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 17 and 18).

In terms of the confidence level that should be attached to the 0.95 probability acceptance standard, it is industry practice for SG tube integrity evaluations, as embodied in industry guidelines, to calculate such probabilities at a 50 percent confidence level. The Westinghouse recommended H* value of 13.8 inches, in Reference 15 for model D5 SGs, is based on probabilistic estimates performed at a 50 percent confidence value. However, as discussed in Section 4.3.1.7, the NRC staff finds that the 16.95 inch H* value proposed by the licensee conservatively bounds an H* value based on probabilistic estimates performed at a 95 percent confidence value.

Another issue relating to the acceptance standard for the probabilistic analysis is determining what population of tubes needs to be analyzed. For accidents such as MSLB or FLB, the NRC staff and licensee both find that the tube population in the faulted SG is of interest, since it is the only SG population that experiences a large increase in the primary-to-secondary pressure differential. However, normal operating conditions were found to be the most limiting in terms of meeting the tube pullout margins in Section 4.3.1.1. 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 15 is based on the population of just one SG, the NRC staff finds that the 16.95 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 4.3.1.7.

4.3.1.7 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 15) for RCP associated with the tube hydraulic expansion process[2], the sensitivity of H* to other geometry and material input parameters was judged by Westinghouse to be inconsequential and were ignored, with the exception of Young's Modulus of elasticity for the tube and tubesheet materials. Although the Young's Modulus parameters were included in the reference H* analyses sensitivity studies, these parameters were found to have a weak effect on the computed H*. Based on its review of the analysis models and its engineering judgment, the NRC staff concurs that the sensitivity studies adequately capture the input parameters that may significantly affect the value of H*. This conclusion is based, in part, on no credit being taken for RCP during the reference H* analyses.

These sensitivity studies were used to develop influence curves describing the change in H*, relative to the mean H* value estimate (see Section 4.3.1.5), as a function of the variability of each CTE parameter and Young's Modulus parameter, relative to the mean values of CTE and Young's Modulus. Separate influence curves were developed for each of the four input parameters. The sensitivity studies showed that of the four input parameters, only the CTE parameters for the tube and tubesheet material had any interaction with one another. A combined set of influence curves containing this interaction effect were also created.

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

The NRC staff reviewed the implementation of probabilistic analyses in the reference analyses (Reference 15) and questioned whether the H* influence curves had been conservatively treated. The NRC staff concluded that the reference analysis was insufficient to support the requested amendments. To address this concern, the licensee submitted new H* analyses as documented in Reference 2. These analyses made direct use of the H* influence curves in a manner the NRC staff finds to be acceptable. To show that the proposed H* value in the subject LAR is conservative, the new analyses eliminated some of the conservatisms in the reference analyses as follows:

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

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2 RCPs are sensitive to variability of other input parameters.

2. The reference analyses add an incremental distance to H* to account for the actual distribution of temperature in the tubesheet under normal operating conditions versus the linear distribution assumed in the reference finite element analyses (see Step 3 in Section 4.3.1.5). 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 16.95 inch H* based on a 0.95 probability/50 percent confidence, single-SG basis. The NRC staff concludes that direct modeling of the actual temperature distribution in the tubesheet provides a more realistic, but still conservative estimate of H*, albeit on a 50 percent confidence, single-SG basis. No H* estimate was provided on a 0.95 probability/95 percent confidence, all-SG basis for this specific case. However, the sensitivity of the calculated H* when evaluated at a 95 percent versus 50 percent confidence level and when evaluated on an all-SG versus single-SG basis was determined for other cases in Reference 19. 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 16.95 inches.

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

The new analyses, Items 1, 2, and 3 above, also address a question posed by the NRC staff in Reference 7 concerning the appropriate way to sample material properties for the tubesheet, whose properties are unknown, but do not vary significantly for a given SG in contrast to the tubes, whose properties tend to vary much more randomly from tube to tube in a given SG. This issue was addressed by a staged sampling process where the tubesheet properties were sampled once and then held fixed, while the tube properties were sampled a number of times equal to the SG tube population. This process was repeated 10,000 times, and the maximum H* value from each repetition was rank ordered. The final H* value was selected from the rank ordering to reflect a 0.95 probability value at the desired level of confidence. The NRC staff concludes that this approach addresses the NRC staff's question in a realistic fashion and is acceptable.

Based on Items 1 and 2, and considering the significant conservatism associated with the assumption of zero RCP, the NRC staff concludes that the proposed H* distance of 16.95 inches for Braidwood, Unit 2, and Byron, Unit No. 2, ensures that all tubes will have acceptable pullout resistance for normal operating and DBAs, even with the conservative assumption that all tubes are severed at the H* distance.

The licensee has committed to monitor for tube slippage as part of the SG inspection program. Under the proposed license amendments, TS 5.6.9.I will require that the results of slippage monitoring be included as part of the 180-day report required by TS 5.6.9. TS 5.6.9.I will also require that should slippage be discovered, the implications of the discovery and corrective action shall be included in the report. The NRC staff finds that slippage is not expected to occur for the reasons discussed previously. In the unexpected event it should occur, it will be important to understand why it occurred so that the need for corrective action can be evaluated. The NRC staff concludes the commitment to monitor for slippage and the accompanying reporting requirements are acceptable.

4.3.1.8 Coefficient of Thermal Expansion

During operation, a large part of contact pressure in a SG T/TS joint is derived from the difference in the CTE between the tube and tubesheet. As discussed in Section 4.3.1.7, the calculated value of H* is highly sensitive to the assumed values of these CTE parameters. However, CTE test data acquired by an NRC contractor, Argonne National Laboratory (ANL), suggested that CTE values may vary substantially from values listed in the ASME Code for design purposes. In Reference 7, the NRC staff highlighted the need to develop a rigorous technical basis for the CTE values, and their potential variability, to be employed in future H* analyses.

In response, Westinghouse had a subcontractor review the CTE data in question, determine the cause of the variance from the ASME Code CTE values, and provide a summary report (Reference 20). 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 were 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 database. Two additional sets of CTE test data (different from those addressed in the previous paragraph) had CTE offsets a low temperature, that were not expected. Review of the test data showed that the first test, conducted in a vacuum, had proceeded to a maximum temperature of 700 °C, which changed the microstructure and the CTE of the steel during decreasing temperature conditions. As a result of the altered microstructure, the CTE test data generated in the second test, conducted in air, were also invalidated. As a result of the large "dead band" region and the altered microstructure, both data sets were excluded from the final CTE values obtained from the CTE testing program.

The test program included multiple material heats to analyze chemistry influence on CTE values and repeat tests on the same samples were performed to analyze for test apparatus influence.

Because the tubes are strain hardened when they are expanded into the tubesheet, strain hardened samples were also measured to check for strain hardening influence on CTE values.

The data from the test program were combined with the ANL data that were found by the licensee to be acceptable, and with the data obtained from the open literature search. A statistical analysis of the data uncertainties was performed by comparing deviations to the mean values obtained at the applicable temperatures. The correlation coefficients obtained indicated a good fit to a normal distribution, as expected. Finally, an evaluation of within-heat variability was performed due to increased data scatter at low temperatures. The within-heat variability assessment determined that the increase in data scatter was a testing accuracy limitation that was only present at low temperature. The CTE report is included as Appendix A to Reference 15.

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 database 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 7 and are acceptable.

4.3.2 Accident-induced Leakage Considerations

Operational leakage integrity is assured by monitoring primary-to-secondary leakage relative to the applicable TS LCO limits in TS 3.4.13, "RCS Operational LEAKAGE." However, it must also be demonstrated that the proposed TS changes do not create the potential for leakage during DBA to exceed the accident leakage performance criteria in TS 5.5.9.b.2, including the leakage values assumed in the plant licensing basis accident analyses.

If a tube is assumed to contain a 100 percent through-wall flaw some distance into the tubesheet, a potential leak path between the primary and secondary systems is introduced between the hydraulically-expanded tubing and the tubesheet. The leakage path between the tube and tubesheet has been modeled by the licensee's contractor, Westinghouse, as a crevice consisting of a porous media. Using Darcy's Model for flow through a porous media, leak rate is proportional to differential pressure and inversely proportional to flow resistance. Flow resistance is a direct function of viscosity, loss coefficient, and crevice length. Westinghouse performed leak tests of T/TS joint mockups to establish loss coefficient as a function of contact pressure. A large amount of data scatter, however, precluded quantification of such a correlation. In the absence of such a correlation, Westinghouse has developed a leakage factor relationship between accident-induced leak rate and operational leakage rate, where the source of leakage is from flaws located at or below the H* distance. Using Darcy's Model, the leakage factor for a given type of 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 isn't known, Westinghouse has assumed that the loss coefficient is constant with contact pressure such that the ratio is equal to 1. The NRC staff agrees that this is a conservative assumption, provided there is a positive contact pressure for both conditions along the entire H* distance and provided that contact pressure increases at each axial location along the H* distance when going from normal operating to accident conditions. Both assumptions were confirmed to be valid in the H* analyses.

Leakage factors were calculated for DBAs exhibiting a significant increase in primary-to-secondary pressure differential, including MSLB, FLB, locked rotor, and control rod ejection. The design basis FLB heat-up transient was found to exhibit the highest leakage factor, 3.11, meaning that it is the transient expected to result in the largest increase in leakage relative to normal operating conditions.

The licensee provided the following commitment in Reference 4 that describes how the leakage factor will be used to satisfy TS 5.5.9.a for condition monitoring and TS 5.5.9.b.2 regarding performance criteria for accident-induced leakage:

> *For the condition monitoring (CM) assessment, the component of operational leakage from the prior cycle from below the H* distance will be multiplied by a factor of 3.11 and added to the total accident leakage from any other source and compared to the allowable accident induced leakage limit. For the operational assessment (OA), the difference between the allowable accident induced leakage and the accident induced leakage from sources other than the tubesheet expansion region will be divided by 3.11 and compared to the observed operational leakage. An administrative operational leakage limit will be established to not exceed the calculated value.*

The NRC staff finds this license commitment acceptable, since it provides further assurance, in addition to the licensee's operational leakage monitoring processes, that accident-induced SG tube leakage will not exceed values assumed in the licensing bases accident analyses. The NRC staff finds that the leakage factor of 3.11 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.

4.3.3 Proposed Change to TS 5.6.9, "Steam Generator (SG) Tube Inspection Report"

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

4.3.4 Technical Bases for Interim H* Amendments

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

As discussed in Section 4.3.1.3, 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 now requesting interim amendments that are applicable to Braidwood, Unit 2, during Refueling Outage 14 (fall 2009), and the subsequent operating cycle, and to Byron, Unit No. 2, during Refueling Outage 15 (spring 2010), and the subsequent operating cycle, rather than amendments that are applicable to the remaining life of the plants. The NRC staff finds that assuming all tubes will be severed at the H* distance over the next operating cycle is unrealistic and that the proposed H* distance is conservative for the next operating cycle for the reasons cited below.

From a fleet-wide perspective (for all Westinghouse plants with tubes fabricated from thermally-treated Alloy 600), the NRC staff has observed from operating experience that the extent of cracking is at an early stage in terms of the number of tubes affected by cracking below the H* distance and in terms of the severity of cracks, compared to the idealized assumption that all tubes are severed at the H* distance. Most of these cracks occur in the lower-most 1 inch of tubing, which is a region of relatively high residual stress associated with the 1 inch tack roll expansion in that region. Although the extent of cracking can be expected to increase with time, it is the 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 generally within 18 months of each SG tube inspection. References 21 and 22 provide recent examples of such reviews for Braidwood, Unit 2, and Byron, Unit No. 2, by the NRC staff.

In Reference 4, the licensee stated that during the most recent Braidwood, Unit 2, refueling outage (spring 2008), 3,625 tubes were inspected through the full depth of the hot-leg tubesheets, and an additional 14,455 hot-leg tubes were inspected at the tube end region. A total of 331 flaws were identified within 0.5 inches of the hot-leg tube end. Only sixteen tubes were required to be plugged, because Braidwood, Unit 2, currently has an approved amendment with interim alternate repair criteria for the SG tubes (Reference 23). All of the flaws were small and did not challenge structural or leakage integrity performance criteria. The total number of tube end flaws found was small compared to the number of tubes inspected. No flaws were found above the tube end region during this inspection or during previous inspections. The licensee stated that during the most recent Byron, Unit No. 2, refueling outage (fall 2008), 3,808 tubes were inspected through the full depth of the hot leg tubesheet, and an additional 14,106 hot-leg tubes were inspected at the tube end region. Additionally, 3,660 tubes were inspected at the cold-leg tube end region. A total of 65 flaws were identified within 0.5 inches of the hot-leg tube end, and no flaws were identified in the cold-leg tube end region. All of the flaws were small and did not require any tubes to be plugged because Byron, Unit No. 2, currently has an approved amendment with interim alternate repair criteria for the SG tubes (Reference 24). None of the flaws challenged any structural or leakage integrity performance criteria. The total number of tube end flaws found was small compared to the number of tubes inspected. No flaws were found above the tube end region during this inspection or during previous inspections.

The licensee also states in Reference 4 that a separate inspection program for tubesheet bulges and over expansions has been implemented at both Braidwood, Unit 2, and Byron, Unit No. 2, during the previous three refueling outages and that no flaws were identified in any of the inspections. The NRC staff finds the extent and severity of cracking at Braidwood, Unit 2, and Byron, Unit No. 2, to be limited and within the envelope of industry experience with similar units.

The NRC staff concludes that there is sufficient conservatism embodied in the proposed H* distances to ensure acceptable margins against tube pullout for at least one operating cycle for the reasons discussed above. The NRC staff also concludes there is reasonable assurance during the next operating cycle that any potential accident-induced leakage will not exceed the TS performance criteria for accident-induced leakage. This reflects current operating experience trends that cracking below the H* distance is occurring predominantly in the tack roll region near the bottom of the tube. At this location, it is the NRC staff's judgment that the total resistance to primary-to-secondary leakage will be dominated by the resistance of any crevice in the roll expansion region (due to very high T/TS contact pressures in this region), such that the leakage factors discussed in Section 4.3.2 will remain conservative even should there be a loss of T/TS contact near the top of the tubesheet due to tubesheet bore eccentricity effects.

4.4 Summary

The NRC staff finds that the amendment request acceptably addresses all issues identified by the NRC staff in Reference 7 relating to H* amendment requests submitted prior to 2008 (which were subsequently withdrawn). However, the NRC staff does not have sufficient information to determine whether the tubesheet bore displacement eccentricity has been addressed in a conservative fashion and, thus, the NRC staff does not have an adequate basis to approve permanent H* amendments. Accordingly, the licensee modified its LAR on September 15, 2009, to request an interim amendment, applicable to Braidwood, Unit 2, during Refueling Outage 14 (fall 2009), and the subsequent operating cycle, and to Byron, Unit No. 2, during Refueling Outage 15 (spring 2010), and the subsequent operating cycle.

Notwithstanding any potential non-conservatism in the calculated H* distance which may be associated with the eccentricity issue, the NRC staff concludes that, given the current state of the tubes, there is sufficient conservatism embodied in the proposed H* distances to ensure, for one operating cycle, that tube structural and leakage integrity will be maintained with structural safety margins consistent with the design basis and with leakage integrity within assumptions employed in the licensing basis accident analyses. Based on this finding, the NRC staff further concludes that the proposed amendments meet 10 CFR 50.36 and, thus, the proposed amendments are acceptable.

5.0 STATE CONSULTATION

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

6.0 ENVIRONMENTAL CONSIDERATION

The amendments change requirements with respect to installation or use of a facility's components located within the restricted area, as defined in 10 CFR Part 20, or changes surveillance requirements. The NRC staff has determined that the amendments involve no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendments involve no significant hazards consideration, and there has been no public comment on such finding (74 FR 38234; July 31, 2009). Accordingly, the amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendments.

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

8.0 REFERENCES

1. EGC, LLC, letter RS-09-071, "License Amendment Request to Revise Technical Specifications (TS) for Permanent Alternate Repair Criteria," June 24, 2009, NRC ADAMS Package No. ML091770543. This letter also transmitted Reference 15.

2. EGC letter RS-09-108, August 14, 2009, responding to Braidwood and Byron RAIs, NRC ADAMS Package No. ML092320375. This letter also transmitted 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," August 12, 2009, NRC ADAMS Accession No. ML092320377 for Non-Proprietary.

3. EGC letter RS-09-117, August 31, 2009, responding to Braidwood and Byron RAI No. 4, NRC ADAMS Package No. ML092460588. This letter also transmitted WEC letter, LTR-SGMP-09-109-P (Proprietary) and LTR-SGMP-09-109-NP (Non-Proprietary) "Response to NRC Request for Additional Information on H*; RAI #4; Model F and D5 Steam Generators," August 25, 2009, NRC ADAMS Accession No. ML092460590 for Non-Proprietary.

4. EGC letter RS-09-127, September 15, 2009, amending its H* application to apply only to the next operating cycle, NRC ADAMS Package No. ML092600168.

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

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

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

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

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

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

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

12. NRC Meeting minutes, "Summary of the October 29 and 30, 2008, Category 2 Public Meeting with the Nuclear Energy Institute (NEI) and Industry to Discuss Modeling Issues Pertaining to the Steam Generator Tube-to-Tubesheet Joints," NRC ADAMS Accession No. ML083300422.

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

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

15. 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, NRC ADAMS Accession No. ML091770546 for Non- Proprietary.

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

17. 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.

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

19. Southern Nuclear Operating Company 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, NRC ADAMS Accession No. ML092450029 (Non-Proprietary).

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

21. NRC letter to EGC, "Braidwood Station, Unit 2 - Review of Twelfth Refueling Outage Steam Generator Tube Inservice Inspection Report," October 17, 2007, NRC ADAMS Accession No. ML072740389.

22. NRC letter to EGC, "Byron Station, Unit 2 - Review of spring 2007 Steam Generator Tube Inservice Inspection Reports," April 14, 2008, NRC ADAMS Accession No. ML080990790.

23. NRC letter to EGC, "Braidwood Station, Units 1 and 2 - Issuance of Amendments Re: Revision to Technical Specifications for the Steam Generator Program," April 18, 2008, NRC ADAMS Accession No. ML080920879.

24. NRC letter to EGC, "Byron Station, Unit Nos. 1 and 2 - Issuance of Amendments Re: Revision to Technical Specifications for the Steam Generator Program," October 1, 2008, NRC ADAMS Accession No. ML082340799.

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

Date: October 16, 2009

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

Sincerely,

/RA/

Marshall J. David, Senior Project Manager
Plant Licensing Branch III-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. STN 50-456, STN 50-457,
STN 50-454, and STN 50-455

Enclosures:
1. Amendment No. 161 to NPF-72
2. Amendment No. 161 to NPF-77
3. Amendment No 166 to NPF-37
4. Amendment No. 166 to NPF-66
5. Safety Evaluation

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