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

October 5, 2012

Mr. Michael J. Pacilio
Senior Vice President
Exelon Generation Company, LLC
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: REVISE TECHNICAL SPECIFICATIONS 5.5.9 AND 5.6.9 FOR PERMANENT ALTERNATE REPAIR CRITERIA (TAC NOS. ME8296, ME8297, ME8298, AND ME8299)

Dear Mr. Pacilio:

The U.S. Nuclear Regulatory Commission (the Commission) has issued the enclosed Amendment No. 170 to Facility Operating License No. NPF-72 and Amendment No. 170 to Facility Operating License No. NPF-77 for the Braidwood Station, Units 1 and 2, respectively; and Amendment No. 177 to Facility Operating License No. NPF-37 and Amendment No. 177 to Facility Operating License No. NPF-66 for the Byron Station, Unit Nos. 1 and 2, respectively. The amendments are in response to your application dated March 20, 2012, as supplemented by letters dated August 14 and 30, 2012.

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,

Michael Mahoney, 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. 170 to NPF-72
2. Amendment No. 170 to NPF-77
3. Amendment No. 177 to NPF-37
4. Amendment No. 177 to NPF-66
5. Safety Evaluation

cc w/encls: Listserv

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. 170
License No. NPF-77

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

   A. The application for amendment by Exelon Generation Company, LLC (the licensee) dated March 20, 2012, as supplemented by letters dated August 14 and 30, 2012, 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 that (i) the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) 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. 170 and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto, are hereby incorporated into the 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 for Braidwood, Unit 1.

FOR THE NUCLEAR REGULATORY COMMISSION

Michael I. Dudek, 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 5, 2012

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. 170
License No. NPF-72

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

   A. The application for amendment by Exelon Generation Company, LLC (the licensee) dated March 20, 2012, as supplemented by letters dated August 14 and 30, 2012, 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 that (i) the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) 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. 170 and the Environmental Protection Plan contained in Appendix B, are 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 if its issuance and shall be implemented within 30 days for Braidwood, Unit 2.

FOR THE NUCLEAR REGULATORY COMMISSION

Michael I. Dudek, 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 5, 2012

ATTACHMENT TO LICENSE AMENDMENT NOS. 170 AND 170

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 Appendix "A" Technical Specifications with the attached 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
Page 3	Page 3
License NPF-77	License NPF-77
Page 3	Page 3
TSs	TSs
3.4.19-1	3.4.19-1
3.4.19-2	3.4.19-2
5.5- 7	5.5- 7
5.5 - 8	5.5 - 8
5.5 - 9	5.5 - 9
5.5 - 10	5.5 -10
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 is 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. 170 and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto, are hereby incorporated into the 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 provision 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 is 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. 170 and the Environmental Protection Plan contained in Appendix B, are 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 provision of 10 CFR Section 50.54(s)(2) will apply.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.19 Steam Generator (SG) Tube Integrity

LCO 3.4.19 SG tube integrity shall be maintained.

<u>AND</u>

All SG tubes satisfying the tube repair criteria shall be plugged in accordance with the Steam Generator Program.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

-----------------------------------NOTE-----------------------------------
Separate Condition entry is allowed for each SG tube.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more SG tubes satisfying the tube repair criteria and not plugged in accordance with the Steam Generator Program.	A.1 Verify tube integrity of the affected tube(s) is maintained until the next refueling outage or SG tube inspection. <u>AND</u> A.2 Plug the affected tube(s) in accordance with the Steam Generator Program.	7 days Prior to entering MODE 4 following the next refueling outage or SG tube inspection
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> SG tube integrity not maintained.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.19.1	Verify SG tube integrity in accordance with the Steam Generator Program.	In accordance with the Steam Generator Program
SR 3.4.19.2	Verify that each inspected SG tube that satisfies the tube repair criteria is plugged in accordance with the Steam Generator Program.	Prior to entering MODE 4 following a SG tube inspection

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program

A Steam Generator Program shall be established and implemented to ensure that SG tube integrity is maintained. In addition, the Steam Generator Program shall include the following provisions:

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected or plugged to confirm that the performance criteria are being met.

b. Performance criteria for SG tube integrity. SG tube integrity shall be maintained by meeting the performance criteria for tube structural integrity, accident induced leakage, and operational LEAKAGE.

   1. Structural integrity performance criterion: All in-service steam generator tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cool down and all anticipated transients included in the design specification) and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.

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 with a depth equal to or exceeding 40% of the nominal wall thickness shall be plugged. The following alternate tube repair criteria shall be applied as an alternative to the 40% depth based criteria:

   For Unit 2, tubes with service-induced flaws located greater than 14.01 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 14.01 inches below the top of the tubesheet shall be plugged upon detection.

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, portions of the tube below 14.01 inches from 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.

5.5.9 Steam Generator (SG) Program (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, if crack indications are found in any SG tube from 14.01 inches below the top of the tubesheet on the hot leg side to 14.01 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.

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 during the inspection outage for each active degradation mechanism,

f. Total number and percentage of tubes plugged to date,

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

h. The effective plugging percentage for all plugging 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, 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,

k. For Unit 2, the calculated accident induced leakage rate from the portion of the tubes below 14.01 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, 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. 177
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 March 20, 2012, as supplemented by letters dated August 14 and 30, 2012, 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 that (i) the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) 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. 177 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 for Byron, Unit No. 1 prior to entering MODE 4 following steam generator inspections required by Technical Specifications 5.5.9 beginning with the Byron, Unit No. 2 spring 2013 refueling outage.

FOR THE NUCLEAR REGULATORY COMMISSION

Michael I. Dudek

Michael I. Dudek, 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 5, 2012

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. 177
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 March 20, 2012, as supplemented by letters dated August 14 and 30, 2012, 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 that (i) the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) 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 and Environmental Protection Plan

The Technical Specifications contained in Appendix A (NUREG-1113), as revised through Amendment No. 177 and the Environmental Protection Plan contained in Appendix B, both of which were attached to License No. NPF-66, 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 for Byron Unit No. 2 prior to entering MODE 4 following steam generator inspections required by Technical Specifications 5.5.9 beginning with the Byron, Unit No. 2 spring 2013 refueling outage.

FOR THE NUCLEAR REGULATORY COMMISSION

Michael I. Dudek

Michael I. Dudek, 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 5, 2012

ATTACHMENT TO LICENSE AMENDMENT NOS. 177 AND 177

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 License and Appendix "A" Technical Specifications with the attached 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
Page 3	Page 3
License NPF-66	License NPF-66
Page 3	Page 3
TSs	TSs
3.4.19-1	3.4.19-1
3.4.19-2	3.4.19-2
5.5-7	5.5 -7
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 and 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. 177 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 license 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 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 rated power) in accordance with the conditions specified herein.

(2) Technical Specifications

The Technical Specifications contained in Appendix A (NUREG-1113), as revised through Amendment No. 177 and the Environmental Protection Plan contained in Appendix B, both of which were attached to License No. NPF-66, 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.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.19 Steam Generator (SG) Tube Integrity

LCO 3.4.19 SG tube integrity shall be maintained.

AND

All SG tubes satisfying the tube repair criteria shall be plugged in accordance with the Steam Generator Program.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

-------------------------------NOTE-------------------------------

Separate Condition entry is allowed for each SG tube.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more SG tubes satisfying the tube repair criteria and not plugged in accordance with the Steam Generator Program.	A.1	Verify tube integrity of the affected tube(s) is maintained until the next refueling outage or SG tube inspection.	7 days
	AND		
	A.2	Plug the affected tube(s) in accordance with the Steam Generator Program.	Prior to entering MODE 4 following the next refueling outage or SG tube inspection
B. Required Action and associated Completion Time of Condition A not met. OR SG tube integrity not maintained.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.19.1	Verify SG tube integrity in accordance with the Steam Generator Program.	In accordance with the Steam Generator Program
SR 3.4.19.2	Verify that each inspected SG tube that satisfies the tube repair criteria is plugged in accordance with the Steam Generator Program.	Prior to entering MODE 4 following a SG tube inspection

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program

A Steam Generator Program shall be established and implemented to ensure that SG tube integrity is maintained. In addition, the Steam Generator Program shall include the following provisions:

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected or plugged to confirm that the performance criteria are being met.

b. Performance criteria for SG tube integrity. SG tube integrity shall be maintained by meeting the performance criteria for tube structural integrity, accident induced leakage, and operational LEAKAGE.

   1. Structural integrity performance criterion: All in-service steam generator tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cool down and all anticipated transients included in the design specification) and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.

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 with a depth equal to or exceeding 40% of the nominal wall thickness shall be plugged. The following alternate tube repair criteria shall be applied as an alternative to the 40% depth based criteria:

   For Unit 2, tubes with service-induced flaws located greater than 14.01 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 14.01 inches below the top of the tubesheet shall be plugged upon detection.

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, portions of the tube below 14.01 inches from 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, if crack indications are found in any SG tube from 14.01 inches below the top of the tubesheet on the hot leg side to 14.01 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.

This page intentionally left blank.

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 during the inspection outage for each active degradation mechanism,

f. Total number and percentage of tubes plugged to date,

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

h. The effective plugging percentage for all plugging 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, 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,

k. For Unit 2, the calculated accident induced leakage rate from the portion of the tubes below 14.01 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, 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. 170 TO FACILITY OPERATING LICENSE NO. NPF-72,

AMENDMENT NO. 170 TO FACILITY OPERATING LICENSE NO. NPF-77,

AMENDMENT NO. 177 TO FACILITY OPERATING LICENSE NO. NPF-37,

AND AMENDMENT NO. 177 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 to the Nuclear Regulatory Commission (NRC, the Commission) dated March 20, 2012 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML120830222), as supplemented by letters dated August 14 and 30, 2012 (ADAMS Accession Nos. ML12229A131 and ML12244A352, respectively), Exelon Generation Company, LLC (the licensee) requested changes to the technical specifications (TSs) for the Braidwood Station (Braidwood), Units 1 and 2, and Byron Station (Byron), Unit Nos. 1 and 2.

The license amendment request (LAR) proposed changes to the inspection scope and repair requirements of TS Section 5.5.9, "Steam Generator (SG) Program" and to the reporting requirements of TS Section 5.6.9, "Steam Generator (SG) Tube Inspection Report." The proposed changes would establish permanent alternate repair criteria for portions of the SG tubes within the tubesheet of the Braidwood, Unit 2, and Byron, Unit No. 2, Model D5 SGs. The proposed changes would also delete the option for performing sleeve repairs of tubes at Braidwood Unit 2 and Byron Unit No. 2 in lieu of plugging.

Because Braidwood and Byron Stations', Units 1 and 2, have common TSs, the licensee docketed the LAR for all four units; however, the permanent alternate repair criteria proposed for Braidwood, Unit 2, and Byron, Unit No. 2, are not applicable to the different model SGs that are installed in Braidwood, Unit 1, and Byron, Unit No. 1. The proposed permanent alternate repair criteria would replace similar, interim criteria as documented in NRC safety evaluation (SE) dated April 13, 2011 (ADAMS Accession No. ML110840580), for Braidwood Unit 2, that was applicable during the spring 2011, refueling outage the subsequent operating cycle and for

Byron, Unit No. 2, that was applicable during the fall 2011 refueling outage and the subsequent operating cycle.

The August 14 and 30, 2012, supplements, contained clarifying information and did not change the NRC staff's initial proposed finding of no significant hazards consideration.

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 thermally treated Alloy 600 (Alloy 600TT) tubes in each SG, each with an outside diameter of 0.750 inches and a nominal wall-thickness of 0.043 inches. The tubes are hydraulically expanded for the full depth of the 21-inch thick tubesheet and are welded to the tubesheet at each tube end. Until the fall of 2004, no instances of stress corrosion cracking affecting the tubesheet region of Alloy 600TT tubing had been reported at any nuclear power plants in the United States (U.S.).

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 Alloy 600TT tubing that is hydraulically expanded against the tubesheet. The crack-like indications at Catawba were found in a tube overexpansion (OXP) that was approximately 7 inches below the top of the tubesheet (hot-leg side) in one tube, and just above the tube-to-tubesheet (T/TS) weld in a region of the tube known as the tack expansion region in several other tubes. Indications were also reported near the T/TS welds, which join the tube to the tubesheet. An OXP is created when the tube is expanded into a tubesheet bore hole that is not perfectly round. These out-of-round conditions were created during the tubesheet drilling process by conditions such as drill bit wandering or chip gouging. The tack expansion is an approximately 1-inch long expansion at each tube end. The purpose of the tack expansion is to facilitate performing the tube-to-tubesheet weld, which is made prior to the hydraulic expansion of the tube over the full tubesheet depth.

Since the initial findings at Catawba, Unit 2, in the fall of 2004, other U.S. nuclear plants with Alloy 600TT tubing 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. 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.

Over time, these cracks can be expected to become more and more extensive, necessitating more extensive inspections of the lower tubesheet region and more extensive tube plugging or repairs, with attendant increased cost and the potential for shortening the useful lifetime of the SGs. To avoid these impacts, the affected licensees and their contractor, Westinghouse, have developed proposed alternative inspection and repair criteria applicable to the tubes in the lowermost region of the tubesheets. These criteria are referred to as the "H*" criteria. H* is the minimum engagement distance between the tube and tubesheet, measured downward from the top of the tubesheet, that is proposed, as needed, to ensure the structural and leakage integrity of the tube to tubesheet joints. The proposed H* proposal would exclude the portions of tubing below the H* distance from inspection and plugging requirements on the basis that flaws below the H* distance are not detrimental to the structural and leakage integrity of the tube to tubesheet joints.

Permanent H* license amendments were requested for a number of plants as early as 2005. The NRC staff identified a number of issues with these early LARs and in subsequent LARs made in 2009, including a request for Braidwood, Unit 2, and Byron, Unit No. 2 (application dated June 24, 2009 - ADAMS Accession No. ML091770545)). The NRC staff was therefore unable to approve these H* LARs on a permanent basis pending resolution of these issues. The NRC staff found it did have a sufficient basis to approve H* amendments on a interim (temporary) basis, based on the relatively limited extent of cracking existing in the lower tubesheet region at the time the interim amendments were approved. The technical basis for approving the interim amendments is provided in detail in the NRC staff's SE's accompanying issuance of these amendments. Interim H* amendments were approved for Braidwood, Unit 2, and Byron, Unit No. 2, as early as April 25, and September 19, 2005 (ADAMS Accession Nos. ML051170149 and ML052230019, respectively), and most recently in April 13, 2010 (ADAMS Accession No. ML11080580).

3.0 REGULATORY EVALUATION

In Title 10 of the *Code of Federal Regulations* (10 CFR) Section 50.36 "Technical Specifications," the requirements related to the content of the TS are established. Pursuant to 10 CFR 50.36, TSs 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 (LCO); (3) surveillance requirements; (4) design features; and (5) administrative controls. The rule does not specify the particular requirements to be included in a plant's TSs.

In 10 CFR 50.36(c)(2), LCOs are stated to be "the lowest functional capability or performance levels of equipment required for safe operation of the facility." For Braidwood and Byron, the pertinent LCOs for the subject LAR are in TS 3.4.19, "Steam Generator (SG) Tube Integrity." In 10 CFR 50.36(d)(5), administrative controls are stated to be, "the provisions relating to organization and management, procedures, recordkeeping, review and audit, and reporting necessary to assure the operation of the facility in a safe manner." This also includes the programs established by the licensee, and listed in the administrative controls section of the TS, for the licensee to operate the facility in a safe manner. For Braidwood and Byron, the pertinent requirements for performing SG tube inspections and repair are in the administrative controls, TS 5.5.9, while the requirements for reporting the SG tube inspections and repair are also in the administrative controls, TS 5.6.8.

TSs 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 Byron and Braidwood, SG tube integrity is maintained by meeting the performance criteria specified in TS 5.5.9.b for structural and leakage integrity, and is 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 and that may satisfy the applicable tube repair criteria. The applicable tube repair criteria, specified in TS 5.5.9.c, requires that tubes found during an inservice inspection (ISI) to contain flaws in a non-sleeved region 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 (without repair) through application of alternate repair criteria provided in TS 5.5.9.c.1, such as is being proposed for Braidwood, Unit 2, and Byron, Unit No. 2. TS 5.5.9.f identifies acceptable repair methods for both Braidwood and Byron Stations. TS 5.5.9.f.1 states there are no approved repair methods for Braidwood, Unit 1, and Byron, Unit No. 1. TS 5.5.9.f.2 identifies an acceptable repair method (i.e., tungsten inert gas (TIG)-welded sleeves) for Braidwood, Unit 2, and Byron, Unit No. 2. Tube repair criteria applicable to the sleeves are contained in TS 5.5.9.c.2 and 3.

TS 3.4.13 includes a limit on operational primary-to-secondary leakage (typically 150 gallons per day (gpd)), beyond which the plant must be promptly shutdown. Should a flaw exceeding the tube repair limit not be detected during the periodic tube surveillance required by the plant technical specifications, the operational leakage limit provides added assurance of timely plant shutdown before tube structural and leakage integrity, consistent with the design and licensing bases, are impaired.

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

General Design Criteria (GDC) in Appendix A to 10 CFR Part 50, provide regulatory requirements which 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" (GDCs 15 and 31), shall be of "the highest quality standards practical" (GDC 30), and shall be designed to permit "periodic inspection and testing...to assess...structural and leaktight integrity" (GDC 32). To this end, 10 CFR 50.55a specifies that components which are part of the RCPB must meet the requirements for Class 1 components in Section III of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), 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 ISI of SG tubing are augmented by additional requirements in the TS.

As part of the plant's licensing bases, PWR licensees are required to analyze the consequences of postulated design-basis accidents (DBA), such as a SG tube rupture and a main steam line break (MSLB). These analyses consider primary-to-secondary leakage that may occur during these events and must show that the offsite radiological consequences do not exceed the applicable limits of the 10 CFR 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 and Byron are being changed because of the proposed amendment and, thus, no radiological consequences of any accident analysis are being changed. The use of the proposed permanent alternate repair criteria does not impact the integrity of the SG tubes, and the SG tubes, therefore, still meet the requirements of the GDC in Appendix A to 10 CFR Part 50, and the requirements for Class 1 components in Section III of the ASME Code. The proposed changes maintain the accident analyses and consequences that the NRC has reviewed and approved for the postulated DBAs for SG tubes.

License Amendment No. 166 is currently approved at Braidwood, Units 1 and 2, and license Amendment 172, is currently approved for Byron, Unit Nos. 1 and 2. These amendments modified TS 5.5.9, "Steam Generator (SG) Program," and TS 5.6.8, "Steam Generator Inspection Report," incorporating interim alternate repair criteria and associated tube inspection and reporting requirements that are applicable to Braidwood, Unit 2, during refueling outage 15 (spring 2011) and the subsequent operating cycle and to Byron, Unit No. 2, during refueling outage 16 (fall 2011) and the subsequent respective operating cycles. The proposed permanent H* amendment is similar to the currently approved interim H* amendments (see Amendment Nos. 166 for Braidwood and 172 for Byron). The specified H* distance would be reduced (relaxed) to 14.01 inches under the proposed amendment from the currently specified value of 16.95 inches. In addition, words limiting the applicability of the amendment to an interim time period are deleted.

In addition to the requested permanent alternate repair criteria, the LAR deletes TS 5.5.9.f which provides provisions for SG tube repair methods in lieu of plugging when flaws are found that exceed the applicable plugging limit in TS 5.5.9.c. This change is being requested for two reasons. One, the currently approved repair method (TIG-welded sleeves) for Braidwood, Unit 2, and Byron, Unit No. 2, has never been used at these units and is no longer commercially available. Two, deletion of the provisions for SG tube repair methods eliminates any potential confusion over how the H* alternate repair criteria may be applied to repaired (i.e., sleeved) tubes. For editorial consistency, all uses of the words "plugged or repaired" and "plug or repair" in TS 3.4.19 and TS 5.5.9 would be changed to "plugged" or "plug" as appropriate. In addition, tube repair criteria in TS 5.5.9.c.2 and 3, which are applicable to the sleeves, would no longer be needed and would, therefore, be deleted.

4.0 TECHNICAL EVALUATION

Proposed Changes to TS 3.4.19, Steam Generator (SG) Tube Integrity

The words "plugged or repaired" appear in the current specification in 3 places. The words "plug or repair" appear in one location. These words would be revised to read "plugged" and "plug," respectively.

Proposed Changes to TS 5.5.9, Steam Generator (SG) Program

The datum for the indicated changes below are the current TSs for Braidwood, Units 1 and 2, including the currently approved interim alternate repair criteria and associated tube inspection and reporting requirements that are applicable to Braidwood, Unit 2 during refueling outage 15 and the subsequent operating cycle. The current TSs for Byron, Unit No. 2, are identical, except "refueling outage 15" is "refueling outage 16." The proposed changes are shown below.

Current TS 5.5.9.a states:

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging or repair of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected, plugged, or repaired to confirm that the performance criteria are being met.

Revised TS 5.5.9.a would state:

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected or plugged to confirm that the performance criteria are being met

Current TS 5.5.9.c states:

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. 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 TS5.5.9.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.

Revised TS 5.5.9.c would state:

c. Provisions for SG tube repair criteria.

   2. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal wall thickness shall be plugged. The

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

For Unit 2 , tubes with service-induced flaws located greater than 14.01 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 14.01 inches below the top of the tubesheet shall be plugged upon detection.

Current TS 5.5.9.d states, in part:

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 from 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]

   3. [No change/Not shown]

   4. 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.

Revised TS 5.5.9.d would state, in part:

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, portions of the tube below 14.01 inches from 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.

   2. [No change/Not shown]

   5. [No change/Not shown]

   6. 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, if crack indications are found in any SG tube from 14.01 inches below the top of the tubesheet on the hot leg side to 14.01 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.

Current TS 5.5.9.f states:

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.

TS 5.5.9.f would be deleted in its entirety.

Current TS 5.6.9 states, in part:

5.6.9 <u>Steam Generator (SG) Tube Inspection Report</u>

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. - d. [No change/Not shown]

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. - 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 SG, the entire primary to secondary leakage should be conservatively assumed to be from one steam generator) during the cycle preceding the inspection which is the subject of the report,

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.

Revised TS 5.6.9 would state, in part:

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. - d. [No change/Not shown]

e. Number of tubes plugged during the inspection outage for each active degradation mechanism,

f. Total number and percentage of tubes plugged to date,

g. - i. [No change/not shown]

j. For Unit 2, 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 SG, the entire primary to secondary leakage should be conservatively assumed to be from one steam generator) during the cycle preceding the inspection which is the subject of the report,

k. For Unit 2, the calculated accident induced leakage rate from the portion of the tubes below 14.01 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, the results of monitoring for tube axial displacement (slippage). If slippage is discovered, the implications of the discovery and corrective action shall be provided

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 the distance below the top of the tubesheet over which sufficient frictional force, with acceptable safety margins, can be developed between each tube and the tubesheet under tube end cap pressure loads associated with normal operating and design basis accident conditions to prevent significant slippage or pullout of the tube from the tubesheet, assuming the tube is fully severed at the H* distance below the top of the tubesheet. For Braidwood, Unit 2, and Byron, Unit No. 2, the proposed H* distance is 14.01 inches. Given that the frictional force developed in the T/TS joint over the H* distance is sufficient to resist the tube end cap pressure loads, it is the licensee's and Westinghouse's position that the length of tubing between the H* distance and the T/TS weld is not needed to resist any portion of the tube end cap pressure loads. Thus, the licensee is proposing to change the TS to not require inspection of the tubes below the H* distance and to exclude tube flaws located below the H* distance (including flaws in the T/TS weld) from the application of the TS tube repair criteria. Under these changes, the T/TS joint would now be treated as a friction joint extending from the top of the tubesheet to a distance below the top of the tubesheet equal to H* for purposes of evaluating the structural and leakage integrity of the joint.

The regulatory standard by which the NRC staff has evaluated the subject LAR is that the amended TS's should continue to ensure that tube integrity will be maintained, consistent with the current design and licensing basis. This includes maintaining structural safety margins consistent with the structural performance criteria in TS 5.5.9.b.1 and the design basis, as is discussed in Section 4.2.1.1 below. In addition, this includes limiting the potential for accident-induced primary-to-secondary leakage to values not exceeding the accident-induced leakage performance criteria in TS 5.5.9.b.2, which are consistent with values assumed in the licensing basis accident analyses. Maintaining tube integrity in this manner ensures that the amended TS are in compliance with all applicable regulations. The NRC staff's evaluation of joint structural integrity and accident-induced leakage integrity is discussed in Sections 4.2.1 and 4.2.2 of this SE, respectively.

The component of the LAR relating to deleting TS 5.5.9.f, which contains provisions for SG tube repair methods (i.e., sleeving), deleting TS 5.5.9.c.2 and 3, which contains tube repair limits applicable to the sleeves, and other related changes for editorial consistency, are evaluated in section 4.2.3 of this SE.

4.2.1 Joint Structural Integrity

4.2.1.1 Acceptance Criteria

Westinghouse has conducted extensive analyses to establish the necessary H* distance to resist pullout under normal operating and DBA conditions. The NRC staff finds that pullout is the structural failure mode of interest since the tubes are radially constrained against axial fishmouth rupture by the presence of the tubesheet. The axial force which could produce pullout derives from the pressure end cap loads due to the primary-to-secondary pressure differentials associated with normal operating and DBA conditions. Westinghouse determined the needed H* distance on the basis of maintaining a factor of three against pullout under normal operating conditions and a factor of 1.4 against pullout under DBA conditions. The NRC staff finds that these are the appropriate safety factors to apply to demonstrate structural integrity. These safety factors are consistent with the safety factors embodied in the structural integrity performance criteria in TS 5.5.9.b.1 and with the design basis; namely, the stress limit criteria in the ASME Code, Section III.

The above approach equates tube pullout to gross structural failure which is conservative. Should the pullout load be exceeded, tube slippage would generally be limited by the presence of adjacent tubes and support structures such that the tube would not be expected to pull out of the tubesheet.

The licensee has committed in a letter dated March 20, 2012, to monitor for tube slippage as part of the SG inspection program. Under the proposed license amendment, 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 in this SE. In the unexpected event it should occur, it will be important to understand why it occurred so that the need for corrective action can be evaluated. The NRC staff concludes the commitment to monitor for slippage and the accompanying reporting requirements are acceptable.

4.2.1.2 3-Dimensional Finite Element Analysis

A detailed 3-dimensional (3-D) finite element analysis (FEA) of the lower SG assembly (consisting of the lower portion of the SG shell, the tubesheet, the channel head, and the divider plate separating the hot- and cold-leg inlet plenums inside the channel head) was performed to calculate tubesheet displacements due to primary pressure acting on the primary face of the tubesheet and SG channel head, secondary pressure acting on the secondary face of the tubesheet and SG shell, and the temperature distribution throughout the entire lower SG assembly. The calculated tubesheet displacements were used as input to the T/TS interaction analysis evaluated in Section 4.2.1.3 below.

The tubesheet bore holes were not explicitly modeled. Instead, the tubesheet was modeled as a solid structure with equivalent material property values selected such that the solid model exhibited the same stiffness properties as the actual perforated tubesheet. This is an approach for analyzing perforated plates that the NRC staff finds acceptable.

Two versions of the 3-D FEA model were used to support the subject LAR. A "reference model" documented in Westinghouse Electric Company report, WCAP-17072-P (Proprietary) and WCAP-17072-NP (Non-Proprietary), Rev. 0, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model D5)," May 2009, ADAMS Accession No. ML101730389 (Non- Proprietary), was submitted to support a previous request for a permanent H* amendment for Braidwood and Byron. The second was a "revised model" described in WCAP-17330-P (Proprietary) and WCAP-17330-NP (Non-Proprietary), Revision 1, "H*: Resolution of NRC Technical Issue Regarding Tubesheet Bore Eccentricity (Model F/Model D5)," (June 2011; ADAMS Accession Nos. ML11188A109 (Proprietary) and ML11188A108 (Non-Proprietary, respectively), which was enclosed with the subject LAR dated March 20, 2012. The reference 3-D FEA model was used to provide displacement input to the thick shell T/TS interaction model described in section 4.2.1.3.1 below. The revised 3-D FEA model was used to provide displacement input to the square cell T/TS interaction model described in Section 4.2.1.3.2, below.

The revised 3-D model employs a revised mesh near the plane of symmetry (perpendicular to the divider plate) to be consistent with the geometry of the square cell model such that the displacement output from the 3-D model can be applied directly to the edges of the square cell model. In addition, the mesh near the top of the tubesheet was enhanced to accommodate high temperature gradients in this area during normal operating conditions. This allowed the temperature distributions throughout the lower SG assembly, including the tubesheet region to be calculated directly in the 3-D FEA from the assumed plant temperature conditions (e.g., from the assumed primary and secondary water temperatures) for each operating condition. The NRC staff finds this a more realistic approach relative to the reference analysis where a linear distribution of temperature was assumed to exist through the thickness of the tubesheet in the 3-D FEA with an adjustment factor being applied to the H* calculations for the case of normal operating conditions to account for the actual temperature distribution in the tubesheet based on sensitivity analyses.

Some non-U.S. nuclear power plants have experienced cracks in the weld between the divider plate and the stub runner attachment on the bottom of the tubesheet. Should such cracks ultimately cause the divider plate to become disconnected from the tubesheet, tubesheet vertical and radial displacements under operational conditions could be significantly increased relative to those for an intact divider plate weld. Although the industry believes that there is little likelihood that cracks such as those seen abroad could cause a failure of the divider plate weld, the 3-D FEA conservatively considered both the case of an intact divider plate weld and a detached divider plate weld to ensure a conservative analysis. The case of a detached divider plate weld was found to produce the most limiting H* values. In the WCAP-17072, a factor was applied to the 3-D FEA results to account for a non-functional divider plate, based on earlier sensitivity studies. The revised 3-D FEA model assumes the upper 5 inches of the divider plate to be non-existent. The NRC staff finds this further improves the accuracy of the 3-D FEA for the assumed condition of a non-functional divider plate.

4.2.1.3 <u>T/TS Interaction Model</u>

4.2.1.3.1 Thick Shell Model

The resistance to tube pullout is the axial friction force developed between the expanded tube and the tubesheet over the H* distance. The friction force is a function of the radial contact pressure between the expanded tube and the tubesheet. In WCAP-17072, Westinghouse used classical thick-shell equations to model the interaction effects between the tubes and tubesheet under various pressure and temperature conditions for purposes of calculating contact pressure (T/TS interaction model). Calculated displacements from the 3-D FEA of the lower tubesheet assembly (see Section 4.2.1.2 above) were applied to the thick shell model as input to account for the increment of tubesheet bore diameter change caused by the primary pressure acting on the primary face of the tubesheet and SG channel head, secondary pressure acting on the secondary face of the tubesheet and SG shell, and the temperature distribution throughout the entire lower SG assembly. However, the tubesheet bore diameter change from the 3-D FEA tended to be non-uniform (eccentric) around the bore circumference. The thick shell equations used in the T/TS interaction model are axisymmetric. Thus, the non-uniform diameter change from the 3-D FEA had to be adjusted to an equivalent uniform value before it could be used as input to the T/TS interaction analysis. A 2-D plane stress finite element model was used to define a relationship for determining a uniform diameter change that would produce the same change to average T/TS contact pressure as would the actual non-uniform diameter changes from the 3-D FEA.

In WCAP-17072, Westinghouse identified a difficultly in applying this relationship to Model D5 SGs under MSLB conditions. In reviewing the reasons for this difficulty, the NRC staff developed questions relating to the conservatism of the relationship and whether the tubesheet bore displacement eccentricities are sufficiently limited such as to ensure that T/TS contact is maintained around the entire tube circumference. This concern was applicable to all SG models with Alloy 600TT tubing. In an NRC letter to Southern Nuclear Operating Company dated November 23, 2009 (ADAMS Accession No. ML093030490), the NRC staff documented a list of questions that would need to be addressed satisfactorily before the NRC staff would be able to approve a permanent H* amendment. These questions related to the technical justification for the eccentricity adjustment, the distribution of contact pressure around the tube circumference, and a new model under development by Westinghouse to address the aforementioned issue encountered with the Model D5 SGs.

On June 14 and 15, 2010, the NRC staff conducted an audit at the Westinghouse Waltz Mill Site (ADAMS Accession No. ML101900227). The purpose of the audit was to gain a better understanding of the H* analysis pertaining to eccentricity, to review draft responses to the NRC staff's questions in the NRC letter dated November 23, 2009, to Southern Nuclear Operating Company, and to determine which documents would need to be provided on the docket to support any future requests for a permanent H* amendment. Based on the audit, including review of pertinent draft responses to the November 23, 2009, letter, the NRC staff concluded that eccentricity does not appear to be a significant variable affecting either average T/TS contact pressure at a given elevation or calculated values of H*. The NRC staff found that average contact pressure at a given elevation is primarily a function of average bore diameter change at that elevation associated with the pressure and temperature loading of the tubesheet. Accordingly, the NRC staff concluded that no adjustment of computed average bore diameter change considered in the thick shell model is needed to account for eccentricities computed by the 3-D FEA. The material reviewed during the audit revealed that computed H* values from the reference analyses continued to be conservative when the eccentricity adjustment factor is not applied.

4.2.1.3.2 Square Cell Model

Documentation for the square cell model is included with the subject LAR for Braidwood and Byron, dated March 20, 2012. The square cell model is a 2-D plane stress FEA model of a single square cell of the tubesheet with a bore hole in the middle and each of the four sides of the cell measuring one tube pitch in length. Displacement boundary conditions are applied at the edges of the cell, based on the displacement data from the revised 3-D FEA model. The model also includes the tube cross-section inside the bore. Displacement compatibility between the tube outer surface and bore inner surface is enforced except at locations where a gap between the tube and bore tries to occur.

This model was originally developed in response to the above-mentioned difficulty encountered when applying the eccentricity adjustment to Model D5 SGs T/TS interaction analysis under MSLB conditions using the thick shell model. Early results with this model indicated significant differences compared to the thick shell model, irrespective of whether the eccentricity adjustment was applied to the thick shell model. The square cell model revealed a fundamental problem with how the results of the 3-D FEA model of the lower SG assembly were being applied to the tubesheet bore surfaces in the thick shell model. As discussed in section 4.2.1.2 above, the perforated tubesheet is modeled in the 3-D FEA model as a solid plate whose material properties were selected such that the gross stiffness of the solid plate is equivalent to that of a perforated plate under the primary-to-secondary pressure acting across the thickness of the plate.

This approach tends to smooth out the distribution of tubesheet displacements as a function of radial and circumferential location in the tubesheet and ignores local variations of the displacements at the actual bore locations. These smoothed out displacements from the 3-D FEA results were the displacements applied to the bore surface locations in the thick shell model. The square cell model provides a means for post-processing the 3-D FEA results such as to account for localized variations of tubesheet displacement at the bore locations as part of T/TS interaction analysis. Based on these findings, square cell models were developed for each of the SG model types including the Model D5 SGs at Braidwood, Unit 2, and Byron, Unit No. 2.

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

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

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

The limiting tube locations in terms of H* were determined during the reference analysis to lie along the plane of symmetry perpendicular to the divider plate. The outer edges of the square cell model conform to the revised mesh pattern along this plane of symmetry in the 3-D FEA model of the lower SG assembly, as discussed in Section 4.2.1.2, above. Because the tubesheet bore holes were not explicitly modeled in the 3-D FEA, only the average displacements along each side of the square cell are known from the 3-D FEA. Three different assumptions for applying displacement boundary conditions to the edges of the square cell model were considered to allow for a range of possibilities about how local displacements might vary along the length of each side. The most conservative assumption, in terms of maximizing the calculated H* distance, was to apply the average transverse displacement uniformly over the length of each edge of the square cell.

Primary pressure acting on the inside tube surface and crevice pressure[1] acting on both the tube outside surface and tubesheet bore surface are not modeled directly as in the case of the thick shell model. Instead, the primary side (inside) of the tube is assumed to have a pressure equal to the primary pressure minus the crevice pressure. Note the crevice pressure varies as a function of the elevation being analyzed, as discussed in Section 4.2.1.4, above.

The NRC staff concludes that the square cell model provides for improved compatibility between the 3-D FEA model of the lower SG assembly and the T/TS interaction model, more realistic and accurate treatment of the T/TS joint geometry, and added conservatism relative to the thick shell model used in the reference analyses.

4.2.1.4 Crevice Pressure Evaluation

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

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

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

---

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

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 at each axial location of the T/TS interaction model and are concluded to be acceptable for this purpose by the NRC staff.

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

4.2.1.5 <u>H* Calculation Process</u>

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

1. Perform initial H* estimate (mean H* estimate) using the T/TS interaction model and 3-D FEA models, assuming nominal geometric and material properties, and assuming that the tube is severed at the bottom of the tubesheet for purposes of defining the contact pressure distribution over the length of the T/TS crevice. Two sets of mean H* estimates are pertinent to the proposed H* value, mean H* estimates calculated with the reference T/TS interaction and 3-D FEA models and mean H* estimates calculated with the square cell T/TS interaction and revised 3-D FEA models. The maximum, mean H* estimate (for the most limiting tube) from the reference analysis is 5.55 inches, for the most limiting case of normal operating conditions (with the associated factor of safety of 3 as evaluated in Section 4.2.1.1 of this SE). This estimate includes the adjustments in items 2 and 3 below. The maximum, mean H* estimate with the square cell model in conjunction with the revised 3-D lower SG FEA model is 10.89 inches. The most limiting loading case for this revised analysis is MSLB (with its associated factor of safety of 1.4). The NRC staff finds that the difference in mean H* estimates between the reference analysis and the revised analysis is dominantly due to the improved post-processing of the 3-D FEA model displacements for application to the T/TS interaction model.

2. In the reference analysis, WCAP-17072, a 0.3-inch adjustment was added to the initial H* estimate to account for uncertainty in the bottom of the tube expansion transition (BET) location relative to the top of the tubesheet, based on an uncertainty analysis on the BET for Model F SGs conducted by Westinghouse. This adjustment is not included in the revised H* analysis accompanying the subject LAR, as discussed and evaluated in section 4.2.1.5.1 of this SE.

3. In WCAP-17072, for normal operating conditions only, an additional adjustment was added to the initial H* estimate to correct for the actual temperature distribution in the tubesheet compared to the linear distribution assumed in the reference 3-D FEA analysis. This adjustment is no longer necessary, as discussed in Section 4.2.1.2 of this SE, since the temperature distributions throughout the tubesheet were calculated directly in the revised 3-D FEA supporting the current request for an permanent H* amendment.

4. Steps 1 through 3 yield a so-called "mean" estimate of H* which is deterministically based. Step 4 involves a probabilistic analysis of the potential variability of H*, relative to the mean estimate, associated with the potential variability of key input parameters for the H* analyses. This leads to a "probabilistic" estimate of H*, which includes the mean estimate. The NRC staff's evaluation of the probabilistic analysis is provided in Sections 4.2.1.6 and 4.2.1.7 of this SE.

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. This step is discussed and evaluated in Section 4.2.1.5.2 of this SE.

6. A new step, step 6, has been added to the H* calculation process since the reference analysis to support the subject LAR. This step involves adding an additional adjustment to the probabilistic estimate of H* to account for the Poisson contraction of the tube radius due to the axial end cap load acting on each tube. This step is discussed and evaluated in Section 4.2.1.5.3 of this SE.

4.2.1.5.1 BET Considerations

The diameter of each tube transitions from its fully expanded value to its unexpanded value near the top of the tubesheet (TTS). The BET region is located a short distance below the TTS so as to avoid any potential for over-expanding the tube above the TTS. In the reference H* analysis (WCAP-17072), a 0.3-inch adjustment was added to the mean H* estimate to account for the BET location being below the TTS based on an earlier survey of BET distances conducted by Westinghouse. This adjustment was necessary since the reference analysis did not explicitly account for the lack of contact between the tube and tubesheet over the BET distance.

The BET measurements, based on eddy current testing, have subsequently been performed for all tubes at Braidwood, Unit 2, and Byron, Unit No. 2. These measurements confirm that the original 0.3-inch BET assumption is bounding on a 95 percentile basis; but that maximum values at Braidwood, Unit 2, and Byron, Unit No. 2, range to 0.79-inches.

However, the most recent H* analyses, WCAP-17330, uses the square cell T/TS interaction model, which has made the need for a BET adjustment unnecessary, as the square cell model shows a loss of contact pressure at the TTS that is greater than the possible variation in the BET location. The loss of contact pressure at the TTS shown in the square cell model (which is unrelated to BET location) is compensated for by a steeper contact pressure gradient than was shown previously in the thick shell model H* analysis. The NRC staff concludes that the proposed H* value adequately accounts for the range of BET values at Braidwood, Unit 2, and Byron, Unit No. 2.

4.2.1.5.2 Crevice Pressure Adjustment

As discussed in Section 4.2.1.5, above, steps 1 through 4 of the H* calculation process leading to a probabilistic H* estimate are performed with the assumption that the tube is severed at the bottom of the tubesheet for purposes of calculating the distribution of crevice pressure as a function of elevation. If the tube is assumed to be severed at the initially computed H* distance and steps 1 through 4 repeated, a new H* may be calculated which will be incrementally larger than the first estimate. This process may be repeated until the change in H* becomes small (convergence). Sensitivity analyses conducted with the thick shell model showed that the delta between the initial H* estimate and final (converged) estimate is a function of the initial estimate for the tube in question. This delta (i.e., the crevice pressure adjustment referred to in step 5 of Section 4.2.1.5 of this SE) was plotted as a function of the initial H* estimate for the limiting loading case and tube radial location. Although the sensitivity study was conducted with the thick shell model, the deltas from this study were used in the square cell model in WCAP-17330 to make the crevice pressure adjustment to H*. Updating this sensitivity study would have been very resource intensive, requiring many new 2-D FEA square cell runs.

In response to an NRC staff question as to whether it is conservative to rely on the existing sensitivity study as opposed to updating it to reflect the square cell model, Westinghouse submitted an analysis in a letter dated January 12, 2012 (ADAMS Accession No. ML1201900227), demonstrating that if the sensitivity study were updated, it would show that the crevice pressure adjustment H* is negative, not positive as is shown by the existing study. This is because the square cell model predicts a much longer zone (six inches) of no T/TS contact below the top of the tubesheet than does the thick shell model. Therefore, the crevice pressure must reduce from primary side pressure at the iterative H* location to secondary side pressure six inches below the top of the tubesheet. This leads to higher predicted pressure differentials across the tube wall over the iterative H* distance than exists during the initial iteration when crevice pressure is initially assumed to vary from primary pressure at the very bottom of the tubesheet to secondary pressure at the very top of the tubesheet. Based on its review of the Westinghouse analysis, the NRC staff concludes that the positive crevice pressure adjustment to H* in the WCAP-17330, which is based on the existing sensitivity study, is conservative and that an updated sensitivity analysis based on use of the square cell model would show that a negative adjustment can actually be justified. Thus, the NRC staff concludes the crevice pressure adjustment performed in support of the proposed H* amendment is conservative and acceptable.

4.2.1.5.3 Poisson Contraction Effect

The axial end cap load acting on each tube is equal to the primary-to-secondary pressure difference times the tube cross-sectional area. For purposes of resisting tube pullout under normal and accident conditions, the end cap loads used in the H* analyses are based on the tubesheet bore diameter, which the NRC staff finds to be a conservative assumption. The axial end cap load tends to stretch the tube in the axial direction, but causes a slight contraction in the tube radius due to the Poisson's radial contraction effect. This effect, by itself, tends to reduce the T/TS contact pressure and, thus, to increase the H* distance. The axial end cap force is resisted by the axial friction force developed at the T/TS joint. Thus, the axial end cap force begins to decrease with increasing distance into the tubesheet, reaching zero at a location before the H* distance is reached. This is because the H* distances are intended to resist pullout under the end cap loads with the appropriate factors of safety applied as discussed in Section 4.2.1.1, above.

A simplified approach was taken to account for the Poisson effect. First, thick shell equations were used to estimate the reduction in contact pressure associated with application of the full end cap load, assuming none of this end cap load has been reacted by the tubesheet. The T/TS contact pressure distributions determined in step 4 of the H* calculation process in Section 4.2.1.5 on this SE, were reduced by this amount. Second, the friction force associated with these reduced T/TS contact pressures were integrated with distance into the tubesheet, and the length of engagement necessary to react one times the end cap loading (i.e., no safety factor applied) was determined. At this distance (termed "attenuation distance" by Westinghouse), the entire end cap loading was assumed to have been reacted by the tubesheet, and the axial load in the tube below the attenuation distance was assumed to be zero. Thus, the T/TS contact pressures below the attenuation distance were assumed to be unaffected by the Poisson radial contraction effect. Finally, a revised H* distance was calculated, where the T/TS contact pressures from step 4 of Section 4.2.1.5 of this SE, were reduced only over the attenuation distance.

The NRC staff finds the simplified approach for calculating the H* adjustment for the Poisson effect to contain significant conservatism relative to a more detailed approach. Regarding the safety factor of unity assumption, Westinghouse states that it is unrealistic to apply a safety factor to a physical effect such as Poisson's ratio. The NRC staff has not reached a conclusion on this point. However, irrespective of whether a safety factor is applied to the Poisson's effect (consistent with Section 4.2.1.1 above), the NRC staff concludes there is ample conservatism embodied in the proposed H* distance to accommodate the difference.

4.2.1.6 Acceptance Standard - Probabilistic Analysis

The purpose of the probabilistic analysis is to develop an H* distance that ensures with a probability of 0.95 that the population of tubes will retain margins against pullout consistent with criteria evaluated in Section 4.2.1.1 of this SE, assuming all tubes to be completely severed at their H* distance. The NRC staff finds this probabilistic acceptance standard is consistent with what the NRC staff has approved previously and is acceptable. For example, the upper voltage limit for the voltage based tube repair criteria in NRC Generic Letter 95-05, "Voltage Based Alternate Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside Diameter Stress Corrosion Cracking," dated August 3, 1995 (ADAMS Accession No. ML031070113), 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 consistent with NRC's NUREG-0844, "NRC Integrated Program for the Resolution of Unresolved Safety Issues A-3, A-4, and A-5 Regarding Steam Generator Tube Integrity," dated September 1988, and NUREG-1570, "Risk Assessment of Severe Accident-Induced Steam Generator Tube Rupture," dated March 1998.

In terms of the confidence level that should be attached to the 0.95 probability acceptance standard, it is industry practice for SG tube integrity evaluations, as embodied in industry guidelines, to calculate such probabilities at a 50-percent confidence level. The NRC staff has been encouraging the industry to revise its guidelines to call for calculating such probabilities at a 95-percent confidence level when performing operational assessments and a 50-percent confidence level when performing condition monitoring as documented in NRC meeting summary dated February 6, 2009 (ADAMS Accession No. ML090370782). In the interim, the calculated H* distances supporting the amendment currently being requested have been evaluated at the 95-percent confidence level, as recommended by the NRC staff.

Another issue relating to the acceptance standard for the probabilistic analysis is determining what population of tubes needs to be analyzed. For accidents such as MSLB or feed line break

(FLB), the NRC staff and licensee agree that the tube population in the faulted SG is of interest, since it is the only SG that experiences a large increase in the primary-to-secondary pressure differential. However, normal operating conditions were found to be the most limiting in terms of meeting the tube pullout margins in Section 4.2.1.1, above. For normal operating conditions, tubes in all SGs at the plant are subject to the same pressures and temperatures. Although there is not a consensus between the NRC staff and industry on which population needs to be considered in the probabilistic analysis for normal operating conditions, the calculated H* distances for normal operating conditions supporting the requested interim amendment are 0.95 probability confidence estimates based on the entire tube population for the plant, consistent with the NRC staff's recommendation.

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

4.2.1.7 Probabilistic Analyses

4.2.1.7.1 Reference Analyses

Sensitivity studies were conducted in the WCAP-17072 and demonstrated that H* was highly sensitive to the potential variability of the coefficients of thermal expansion (CTE) for the Alloy 600TT tubing material and the stainless steel SA-508 Class 2a tubesheet material. Given that no credit was taken in the WCAP-17072 for residual contact pressure associated with the tube hydraulic expansion process[2], the sensitivity of H* to other geometry and material input parameters was judged by Westinghouse to be inconsequential and were ignored, with the exception of Young's modulus of elasticity for the tube and tubesheet materials. Although the Young's modulus parameters were included in the reference H* analyses sensitivity studies, these parameters were found to have a weak effect on the computed H*. Based on its review of the analysis models and its engineering judgment, the NRC staff considers that the sensitivity studies adequately capture the input parameters which may significantly affect the value of H*. This conclusion is based, in part, on no credit being taken for RCP during the reference H* analyses.

These sensitivity studies were used to develop influence curves describing the change in H*, relative to the mean H* value estimate (see Section 4.2.1.5, above), 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 of elasticity. Separate influence curves were developed for each of the four input parameters. The sensitivity studies showed that of the four input parameters, only the CTE parameters for the tube and tubesheet material had any interaction with one another. A combined set of influence curves containing this interaction effect were also created.

Two types of probabilistic analyses were performed independently in the reference analyses. One was a simplified statistical approach utilizing a "square root of the sum of the squares" method and the other was a detailed Monte Carlo sampling approach. The NRC staff's review of the reference analysis relied on the Monte Carlo analysis, which provides the most realistic treatment of uncertainties. The NRC staff reviewed the implementation of probabilistic analyses in the reference analyses and questioned whether the H* influence curves had been

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

conservatively treated. To address this concern, new H* analyses were performed as documented in letters from Westinghouse dated August 12, 2009, and Southern Nuclear Company dated August 13, 2009 (ADAMS Accession Nos. ML101730391 and ML092450029, respectively). These analyses made direct use of the H* influence curves in a manner the NRC staff finds to be acceptable.

The revised reference analyses in the letter from Westinghouse dated August 12, 2009, divided the tubes by sector location within the tube bundle and all tubes were assumed to be at the location in their respective sectors where the initial value of H* (based on nominal values of material and geometric input parameters) was at its maximum value for that sector. The H* influence curves discussed above, developed for the most limiting tube location in the tube bundle, were conservatively used for all sectors.

The revised reference analyses in August 12, 2009, Westinghouse letter, also addressed a question posed by the NRC staff 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 for a single SG tube population or all SG population, as appropriate. The NRC staff concludes that this approach addresses the NRC staff's question in a realistic fashion and is acceptable.

The reference analyses in WCAP-17072 and Westinghouse's August 12, 2009, letter indicated normal operating conditions (with associated safety factor of 3) to be the limiting case for determining H* for Model D5 SGs. As discussed earlier in Section 4.2.1.5 of this SE, subsequent analyses with the more accurate square cell model and revised 3-D FEA model (due to the improved displacement compatibility between the two models) show that MSLB (with associated safety factor of 1.4) to be the limiting case for the Model D5 SGs. Accordingly, the reference analyses for the Model D5 SGs, including Braidwood, Unit 2, and Byron, Unit No. 2, were rerun for the case of MSLB to support the subject amendment request

4.2.1.7.2 Revised Analyses to Reflect Square Cell and Revised 3-D FEA Models

New Monte Carlo analyses using the square cell model to evaluate the statistical variability of H* due to the CTE variability for the tube and tubesheet materials were not performed. This was because such an approach would have been extremely resource intensive and a simpler approach involving good approximation was available. The simplified approach involved using the results of the Monte Carlo analyses from the reference analysis, which are based on the thick shell T/TS interaction model, to identify CTE values for the tube and tubesheet associated with the probabilistic H* values near the desired rank ordering. Tube CTE values associated with the upper 10-percent rank order estimates are generally negative variations from the mean value whereas tubesheet CTE values associated with the higher ranking order estimates are generally positive variations from the mean value. For the upper 10-percent of the Monte Carlo results ranking order, a combined uncertainty parameter, "alpha," was defined as the square root of the sum of the squares of the associated tube and tubesheet CTE values for each Monte Carlo sample. Alpha was plotted as a function of the corresponding H* estimate and separately as a function of rank order. Each of these plots exhibited well defined "break lines," representing the locus of maximum H* estimates and maximum rank orders associated with a given values of alpha. From these plots, three paired sets of tube and tubesheet CTE values, located near the break line, were selected. One of these pairs was for the rank order corresponding to an upper 95 percent probability (95-percent confidence) value for H* on a per SG basis, which the NRC staff finds is appropriate for MSLB (see Section 4.2.1.6, above).

These CTE values were then input to the lower SG assembly 3-D FEA model and the square cell model to yield probabilistic H* estimates which approximate the H* values for these same rank orderings had a full Monte Carlo been performed with the square cell and revised 3-D FEA models. These H* estimates were then plotted as a function of rank ordering, allowing the interpolation of H* values at the other rank orders. The resulting 95-percent probability (95-percent confidence) upper bound H* estimate is 11.52-inches, which compares to the mean estimate of 10.89-inches as discussed in section 4.2.1.5 of this SE. With adjustments for Poisson's effect (see Section 4.2.1.5.3, above) and crevice pressure (Section 4.2.1.5.2, above), the final 95-percent probability (95-percent confidence) upper bound H* estimate is 14.01-inches which is the value in the subject LAR.

The NRC staff believes that the above break line approach to be a very good approximation of what an actual Monte Carlo analysis would show. A perfect approximation would mean that if hypothetically one were to perform a square cell analysis for each paired set of tube and tubesheet CTE values associated with the top 10-percent of rank orders and plot the resulting H* values versus the original rank ordering associated with the CTE couple, the calculated H* values should monotonically increase from rank order to rank order. Westinghouse performed additional square cell analyses with CTE pairs for five consecutive rank orders for both Model D5 and Model F SGs. The results showed deviations from monotonically increasing values of H* with rank order to be on the order of only 0.3-inches for the Model D5 SGs and 0.1-inches for the Model F SGs. The NRC staff concludes that use of the break line approach adds little imprecision to the probabilistic H* estimates and is acceptable.

4.2.1.8 Coefficient of Thermal Expansion

During normal operation, a large part of contact pressure in a SG tube-to-tubesheet joint is derived from the difference in CTE between the tube and tubesheet. As discussed in section 4.2.1.7 of this SE, 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 NRC letter to Wolf Creek Nuclear Operating Corporation, dated February 28, 2008 (ADAMS Accession No. ML080450185), 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 provided a summary report documented in a letter from the Nuclear Energy Institute (NEI) dated July 7, 2009 (ADAMS Accession No. ML082100097). 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 (degrees Fahrenheit) to 1300 °F. The polynomial fit chosen resulted in mean CTE values that were significantly different from the ASME Code values from 75 °F to about 300 °F.

When the raw data was reanalyzed using the locally weighted least squares regression method, the mean CTE values determined were in good agreement with the established ASME Code values.

Westinghouse also formed a panel of licensee experts to review the available CTE data in open literature, review the ANL-provided CTE data, and perform an extensive CTE testing program on Alloy 600TT and SA-508 material to supplement the existing data base. Two additional sets of CTE test data (different from those addressed in the previous paragraph) had CTE offsets at low temperatures 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 1,300 °F, which changed the microstructure and the CTE of the steel during decreasing temperature conditions. As a result of the altered microstructure, the CTE test data generated in the second test, conducted in air, was also invalidated. As a result of the large "dead band" region and the altered microstructure, both data sets were excluded from the final CTE values obtained from the CTE testing program. The test program included multiple material heats to analyze chemistry influence on CTE values and repeat tests on the same samples were performed to analyze for test apparatus influence. Because the tubes are strain hardened when they are expanded into the tubesheet, strain hardened samples were also measured to check for strain hardening influence on CTE values.

The data from the test program was combined with the ANL data that was found to be acceptable and 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 WCAP-17072.

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

Based on its review of the Westinghouse CTE program, the NRC staff concludes that the CTE values used in the H* analyses are fully responsive to the concerns stated in NRC letter dated February 28, 2008, and are acceptable.

4.2.2 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 tube-to-tubesheet joint mockups to establish loss coefficient as a function of contact pressure. This resulted in a large amount of data scatter, precluding quantification of such a correlation. In the absence of such a correlation, Westinghouse has developed a leakage factor relationship between accident induced leak rate and operational leakage rate, where the source of leakage is from flaws located at or below the H* distance.

Using the Darcy model, the leakage factor for a given type accident is the product of four quantities. The first quantity is ratio of the maximum primary-to-secondary pressure difference during the accident divided by that for normal operating conditions. The second quantity is the ratio of viscosity under normal operating primary water temperature divided by viscosity under the accident condition primary water temperature. The third quantity is the ratio of crevice length under normal operating conditions to crevice length under accident conditions. This ratio equals one, 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 one. The NRC staff agrees that this is a conservative assumption, provided there is a positive contact pressure for both conditions along the entire H* distance and provided that contact pressure increases at each axial location along the H* distance when going from normal operating to accident conditions. Both assumptions were confirmed to be valid in the H* analyses.

Leakage factors were calculated for design basis accidents exhibiting a significant increase in primary-to-secondary pressure differential, including MSLB, 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 latest H* analyses, WCAP-17330, did not show an increasing T/TS contact pressure when going from normal operating to MSLB conditions. The new analyses used the revised 3-D finite element model of the lower SG assembly and the new square cell model, discussed in section 4.2.1.3.2 of this SE. Although T/TS contact pressure increased over some sections of the tubing under SLB conditions, it decreased over other sections within the H* distance. This violated the assumed precondition for assuming that the ratio of loss coefficient under MSLB and normal operating conditions was at least equal to one.

As discussed above, the large data scatter of the loss coefficient versus contact pressure data prevented direct use of this data in applying Darcy's leakage model. Instead, Westinghouse considered a number of mathematical functions that represented the potential functional relationship between loss coefficient and contact pressure. For each potential functional relationship, Westinghouse evaluated the ratio of loss coefficient under MSLB and normal operating conditions, at each elevation and radial location within the tubesheet. For each tube, this ratio was integrated over the length of the H* distance yielding a ratio of flow resistances for MSLB and normal operating conditions. This ratio, in conjunction with the differential pressure and viscosity ratios, was then used to compute the ratio of leakage under MSLB and normal operating conditions, at each radial location within the tubesheet. None of the potential functional relationships between loss coefficient and contact pressure considered by Westinghouse resulted in a leakage ratio value exceeding the value of 3.11 calculated for FLB.

Westinghouse performed additional analyses using parallel plate flow theory, benchmarked with the leak rate versus contact pressure data discussed above, to show that resistance to leakage under both normal operating and MSLB conditions is primarily developed in the lower portion of the H* distance and that the leak rate ratio existing in this region dominates the overall leakage ratio existing over the entire H* distance and that this ratio is less than 1.5. For the NRC staff, confidence that MSLB is not the limiting case for calculating leakage ratio derives from the fact that contact pressures are higher for MSLB than for normal operating conditions for the lower region of the H* distance where most of the resistance to leakage is developed. The NRC staff concludes that the calculated leakage factor of 3.11 for Braidwood, Unit 2, and Byron, Unit No. 2 is a reasonably conservative bound for all relevant loading conditions.

In the March 20, 2012, LAR, the licensee provided a commitment for Braidwood, Unit 2, and Byron, Unit No. 2, describing 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 limit will be established to not exceed the calculated value.

Excluding this commitment from the Braidwood and Byron licenses, it is consistent with performance of condition monitoring and operational assessments, which are generally not included as part of the operating license, including the TSs. Extensive industry guidance on conducting condition monitoring and operational assessments is available as part of the industry NEI 97-06 initiative, "Steam Generator Program Guidelines," (ADAMS Accession No.

ML111310708). The above commitment ensures that plant procedures address the above leakage factor issue in accordance with industry guidelines.

The subject LAR includes reporting requirements (TSs 5.6.8.h and 5.6.8.i) relating to operational leakage existing during the cycle preceding each SG inspection and condition monitoring assessment, and the associated potential for accident induced leakage from the lower portion of the tubesheet below the H* distance. These reporting requirements will allow the NRC staff to monitor how the leakage factor is actually being used, and are acceptable.

4.2.2 Deletion of Requirements Relating to Tube Repair Methods (Sleeving)

In addition to the requested permanent alternate repair criteria, the March 20, 2012, LAR deletes TS 5.5.9.f, which provides provisions for SG tube repair methods in lieu of plugging when flaws are found that exceed the applicable plugging limit in TS 5.5.9.c (as documented in the licensees supplemental letter dated August 14, 2012). This change is being requested for two reasons. First, the currently approved repair method (TIG-welded sleeves) for Braidwood, Unit 2 and Byron, Unit No. 2, has never been used at these units and is no longer commercially available. Second, deletion of the provisions for SG tube repair methods addresses an NRC staff concern in NRC letter dated August 12, 2012 (ADAMS Accession No. ML12206A501), by eliminating any potential confusion over how the H* alternate repair criteria may be applied to repaired (i.e., sleeved) tubes. For editorial consistency, all uses of the words "plugged or repaired" and "plug or repair" in TSs 3.4.19 and 5.5.9 would be changed to "plugged" or "plug," as appropriate.

In addition, tube repair criteria in TSs 5.5.9.c.2 and 5.5.9.c.3, which are applicable to the sleeves, would no longer be needed and would, therefore, be deleted. These changes, in aggregate, eliminate the licensee's option to repair tubes by sleeving when applicable tube repair criteria are not met in lieu of removing the tubes from service by plugging the tube ends. The NRC staff concludes that these changes have no adverse impact on the effectiveness of the technical specifications for ensuring that SG tube integrity is maintained and that these changes 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 amendment. The State official had no comments.

6.0 ENVIRONMENTAL CONSIDERATION

The amendments change the requirements with respect to installation or use of a facility's components located within the restricted area as defined in 10 CFR Part 20. The NRC staff has determined that the amendments involve no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendments involve no significant hazards consideration, and there has been no public comment on such finding (77 FR 35072: dated June 12, 2012). 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

Since the initial proposal for a permanent H* amendment in 2005, the supporting technical analyses have undergone substantial revision and refinement to address NRC staff questions and issues. The current analyses supporting the proposed permanent license amendment still embody uncertainties and issues (e.g., should a factor of safety be applied to Poisson's effect) as discussed throughout this SE. However, it is important to acknowledge that there are significant conservatisms in the analyses. Some examples, also discussed elsewhere in this SE, include not taking credit for residual contact pressures associated with the hydraulic tube expansion process, the assumed value of 0.2 for coefficient of friction between the tube and tubesheet, and not taking credit for constraint against pullout provided by adjacent tubes and support structures. The NRC staff has evaluated the potential impact of the uncertainties and concludes these uncertainties to be adequately bounded by the significant conservatism within the analyses and proposed H* distance.

The NRC staff finds the proposed changes to the Braidwood, Unit 2 and Byron, Unit No. 2 TSs ensure that tube structural and leakage integrity will be maintained with structural safety margins consistent with the design basis and with leakage integrity within assumptions employed in the licensing basis accident analyses, without undue risk to public health and safety. Based on this finding, the NRC staff further concludes that the proposed amendment meets 10 CFR 50.36 and, thus, the proposed amendment is acceptable.

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) there is reasonable assurance that such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

Principal Contributor: E. Murphy, NRR

Date of issuance: October 5, 2012

Mr. Michael J. Pacilio
Senior Vice President
Exelon Generation Company, LLC
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: REVISE TECHNICAL SPECIFICATIONS 5.5.9 AND 5.6.9 FOR PERMANENT ALTERNATE REPAIR CRITERIA (TAC NOS. ME8296, ME8297, ME8298, AND ME8299)

Dear Mr. Pacilio:

The U.S. Nuclear Regulatory Commission (the Commission) has issued the enclosed Amendment No. 170 to Facility Operating License No. NPF-72 and Amendment No. 170 to Facility Operating License No. NPF-77 for the, Braidwood Station, Units 1 and 2, respectively, and Amendment No. 177 to Facility Operating License No. NPF-37 and Amendment No. 177 to Facility Operating License No. NPF-66 for the Byron Station, Unit Nos. 1 and 2, respectively. The amendments are in response to your application dated March 20, 2012 as supplemented by letters dated August 14 and 30, 2012.

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 /
Michael Mahoney, 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. 170 to NPF-72
2. Amendment No. 170 to NPF-77
3. Amendment No. 177 to NPF-37
4. Amendment No. 177 to NPF-66
5. Safety Evaluation

cc w/encls: Listserv

DISTRIBUTION:
PUBLIC RidsNrrDeEsgb Resource LPL3-2 R/F RidsOgcRp Resource
RidsRgn3MailCenter Resource RidsNrrDorlLpl3-2 Resource RidsNrrLASRohrer Resource RidsAcrsAcnw_MailCTR Resource
RidsNrrPMByron Resource RiidsNrrDorlDpr Resource RidsNrrPMBraidwood Resource

ADAMS Accession No.: ML12262A360 *By memo dated

OFFICE	DORL/LPL3-2/PM	DORL/LPL3-2/LA	DE/ESGB/BC
NAME	MMahoney	SRohrer	GKulesa*
DATE	9/19/12	9/19/12	9/10/12
OFFICE	OGC	DORL/LPL3-2/BC	DORL/LPL3-2/PM
NAME	LSubin (NLO w/Comments)	MDudek	MMahoney
DATE	9/27/12	10/4/12	10/5/12

OFFICIAL RECORD COPY