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RS-12-023 10 CFR 50.90

March 20, 2012

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
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Braidwood Station, Units 1 and 2
Facility Operating License Nos. NPF-72 and NPF-77
NRC Docket Nos. STN 50-456 and STN 50-457

Byron Station, Units 1 and 2
Facility Operating License Nos. NPF-37 and NPF-66
NRC Docket Nos. STN 50-454 and STN 50-455

Subject: License Amendment Request to Revise Technical Specifications (TS) Sections 5.5.9, "Steam Generator (SG) Program," and TS 5.6.9, "Steam Generator (SG) Tube Inspection Report," for Permanent Alternate Repair Criteria

In accordance with 10 CFR 50.90, "Application for amendment of license, construction permit, or early site permit," Exelon Generation Company, LLC, (EGC) requests an amendment to Facility Operating License Nos. NPF-72 and NPF-77 for Braidwood Station, Units 1 and 2, and Facility Operating License Nos. NPF-37 and NPF-66 for Byron Station, Units 1 and 2. This amendment request proposes to revise the Braidwood and Byron Technical Specifications (TS) 5.5.9, "Steam Generator (SG) Program," to permanently exclude portions of the SG tube below the top of the steam generator tubesheet from periodic steam generator tube inspections and plugging or repair for Braidwood Unit 2 and for Byron Unit 2. In addition, this amendment request proposes to revise TS 5.6.9, "Steam Generator (SG) Tube Inspection Report," to remove reference to the previous temporary alternate repair criteria and provide reporting requirements specific to the permanent alternate repair criteria. The proposed changes to the TS are based on the supporting structural analysis and leakage evaluation completed by Westinghouse Electric Company LLC (Westinghouse). The documentation supporting the Westinghouse analyses is described in Section 4.0 of Attachment 1, including WCAP-17330-P, "H*: Resolution of NRC Technical Issue Regarding Tubesheet Bore Eccentricity (Model F/ Model D5)," Revision 1, June 2011.

Although the proposed changes only affect Braidwood Station Unit 2 and Byron Station Unit 2, this submittal is being docketed for Braidwood Station Unit 1 and Unit 2 and Byron Station Unit 1 and Unit 2 since the TS are common to both units for the Braidwood and Byron Stations.

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The attached request is subdivided as follows:

- Attachment 1 provides an evaluation of the proposed changes.

- Attachments 2 and 3 include the marked-up TS pages with the proposed changes indicated for the Braidwood Station and the Byron Station, respectively.

- Attachment 4 and 5 include the marked-up TS Bases pages with the proposed changes indicated for the Braidwood Station and the Byron Station, respectively. The TS Bases pages are provided for NRC information only and do not require NRC approval.

- The regulatory commitments contained in this letter are summarized in a table in Attachment 6.

- Attachment 7 provides Westinghouse letter CAW-12-3369, "Application for Withholding Proprietary Information from Public Disclosure," with accompanying affidavit.

- Attachment 8 provides Westinghouse WCAP-17330-P, "H*: Resolution of NRC Technical Issue Regarding Tubesheet Bore Eccentricity (Model F/Model D5)," Revision 1, June 2011 (Proprietary).

- Attachment 9 provides Westinghouse WCAP-17330-NP, "H*: Resolution of NRC Technical Issue Regarding Tubesheet Bore Eccentricity (Model F/Model D5)," Revision 1, June 2011 (Non-Proprietary).

- Attachment 10 provides Westinghouse LTR-SGMP-11-58, WCAP-17330-P, Revision 1 Erratum," (July 2011) (Proprietary). This letter corrects a transcription error identified in Table 3-30 of WCAP-17330, Revision 1.

As Attachments 8 and 10 contain information proprietary to Westinghouse Electric Company LLC, they are supported by an affidavit signed by Westinghouse, the owner of the information. The affidavit sets forth the basis on which the information may be withheld from public disclosure by the NRC and addresses with specificity the considerations listed in paragraph (b)(4) of 10 CFR 2.390, "Public inspections, exemptions, requests for withholding." Accordingly, it is respectfully requested that the information that is proprietary to Westinghouse be withheld from public disclosure in accordance with 10 CFR 2.390.

Correspondence with respect to the copyright or proprietary aspects of Attachments 8 or 10 or the supporting Westinghouse affidavit should reference CAW-12-3369 and should be addressed to J. A. Gresham, Manager, Regulatory Compliance, Westinghouse Electric Company LLC, Suite 428, 1000 Westinghouse Drive, Cranberry Township, Pennsylvania, 16066.

The proposed changes have been reviewed by the Braidwood and Byron Station Plant Operations Review Committees and approved by their respective Nuclear Safety Review Boards in accordance with the requirements of the EGC Quality Assurance Program.

EGC requests approval of the proposed license amendment request for the Braidwood and Byron permanent alternate repair criteria by October 1, 2012, to support SG inspection activities during the Braidwood Unit 2 fall 2012 refueling outage (A2R16) and Byron Unit 2 spring 2013 refueling outage (B2R17). Once approved, the amendment will be implemented for Braidwood Unit 2 within 30 days and implemented for Byron Unit 2 prior to entering MODE 4 following SG inspections required by TS 5.5.9 beginning with the Unit 2 spring 2013 refueling outage (B2R17). The existing one-time alternate repair criteria amendments expire at the end of the current operating cycles.

In accordance with 10 CFR 50.91, "Notice for public comment; State consultation," paragraph (b), EGC is notifying the State of Illinois of this application for license amendment by transmitting a copy of this letter and its attachments to the designated State Official.

Should you have any questions concerning this letter, please contact Ms. Lisa A. Simpson at (630) 657-2815.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 20th day of March 2012.

Respectfully,

David M. Gullott
Manager – Licensing
Exelon Generation Company, LLC

Attachments:

1) Evaluation of Proposed Changes
2) Proposed Technical Specification Changes for Braidwood Station, Units 1 and 2
3) Proposed Technical Specification Changes for Byron Station, Units 1 and 2
4) Proposed Technical Specification Bases Changes for Braidwood Station, Units 1 and 2
5) Proposed Technical Specification Bases Changes for Byron Station, Units 1 and 2
6) Summary of Regulatory Commitments
7) Westinghouse Affidavit and Authorization Letter CAW-12-3369
8) Westinghouse WCAP-17330-P, Revision 1 (Proprietary)
9) Westinghouse WCAP-17330-NP, Revision 1 (Non-Proprietary)
10) Westinghouse LTR-SGMP-11-58, Revision 0 (Proprietary)

cc: NRC Regional Administrator, Region III
NRC Senior Resident Inspector, Braidwood Station
NRC Senior Resident Inspector, Byron Station
NRC Project Manager, NRR – Braidwood and Byron Stations

Bcc (Electronic with all Attachments):

Site Vice President – Braidwood Station
Site Vice President – Byron Station
Regulatory Assurance Manager – Braidwood Station
Regulatory Assurance Manager – Byron Station
Exelon Document Control Desk Licensing
Illinois Emergency Management Agency - Division of Nuclear Safety

Bcc (Electronic w/o Attachments 7, 8, 9, or 10):

Director – Licensing and Regulatory Affairs
Manager – Licensing, Braidwood and Byron Stations
Engineering Director – Braidwood Station
Engineering Director – Byron Station
Commitment Tracking Coordinator – Midwest
G. Contrady (Byron)
R. Cragg (Braidwood)
P. Creegan (Byron)
L. Dworakowski (Braidwood)
J. Langan (Byron)
S. Queen (Cantera)
M. Sears (Braidwood)
L. Simpson (Cantera)
J. Smith (Cantera)

ATTACHMENT 1
Evaluation of Proposed Changes

1.0 SUMMARY DESCRIPTION

2.0 DETAILED DESCRIPTION

3.0 BACKGROUND

4.0 SUMMARY OF LICENSING BASIS ANALYSIS (H* ANALYSES)

5.0 TECHNICAL EVALUATION

6.0 REGULATORY EVALUATION

- 6.1 Applicable Regulatory Requirements/Criteria
- 6.2 Precedents
- 6.3 No Significant Hazards Consideration
- 6.4 Conclusion

7.0 ENVIRONMENTAL CONSIDERATION

8.0 REFERENCES

1.0 SUMMARY DESCRIPTION

Exelon Generation Company, LLC, (EGC) proposes to revise the Braidwood and Byron Technical Specifications (TS) 5.5.9, "Steam Generator (SG) Program," to permanently exclude portions of the steam generator (SG) tube below the top of the SG tubesheet from periodic tube inspections and plugging or repair for Braidwood Unit 2 and Byron Unit 2. Application of the supporting structural analysis and leakage evaluation results to exclude portions of the tubes from inspection and repair of tube indications is interpreted to constitute a redefinition of the primary-to-secondary pressure boundary. In addition, this amendment request proposes to revise TS 5.6.9, "Steam Generator (SG) Tube Inspection Report," to remove reference to the previous temporary alternate repair criteria and provide reporting requirements specific to the permanent alternate repair criteria. The proposed changes to the TS are based on the supporting structural analysis and leakage evaluation completed by Westinghouse Electric Company LLC (Westinghouse). The documentation supporting the Westinghouse analysis is described in Section 4.0 and provides the licensing basis for this change.

WCAP-17072-P, Revision 0, (Reference 1) determined the H* inspection 95/50 whole plant depth of 13.8 inches from the top of the tubesheet. Table 5-1 of WCAP-17330-P, Revision 1, (Reference 2) determined the 95/95 whole bundle depth of 14.01 inches from the top of the tubesheet for plants with Model D5 Steam Generators which includes Braidwood Unit 2 and Byron Unit 2. Exelon is therefore using the value of 14.01 inches. As such, the Braidwood Unit 2 and Byron Unit 2 inspection programs provide a high level of confidence that the structural and leakage criteria are maintained during normal operating and accident conditions.

The NRC previously issued Braidwood and Byron the following amendments revising steam generator tube inspection requirements:

- Amendment Number 135 for Braidwood to exclude degradation found in the portion of the tubes below 17 inches from the top of the hot leg tubesheet from the requirements to plug for Unit 2 refueling outage (A2R11) and the subsequent operating cycle (Reference 3).
- Amendment Number 144 for Byron to exclude degradation found in the portion of the tubes below 17 inches from the top of the hot leg tubesheet from the requirement to plug for Unit 2 refueling outage (B2R12) and the subsequent operating cycle (Reference 4).
- Amendment Number 141 for Braidwood to exclude degradation found in the portion of the tubes below 17 inches from the top of the hot leg tubesheet from the requirement to plug for Unit 2 refueling outage (A2R12) and the subsequent operating cycle (Reference 5).
- Amendment Number 150 for Byron to exclude degradation found in the portion of the tubes below 17 inches from the top of the hot leg tubesheet from the requirement to plug for Byron Unit 2 spring 2007 refueling outage (B2R13) (Reference 6).

- Amendment Number 150 for Braidwood which approved a one-cycle interim alternate repair criteria for the Braidwood Unit 2 spring 2008 refueling outage (A2R13) and the subsequent operating cycle (Reference 7).

- Amendment Number 158 for Byron which approved a one-cycle interim alternate repair criteria for the Byron Unit 2 fall 2008 refueling outage (B2R14) and the subsequent operating cycle (Reference 8).

- Amendment Numbers 161 and 166 for Braidwood and Byron, respectively, to exclude portions of the tube below 16.95 inches from the top of the SG tubesheet from periodic SG inspections and plugging or repair and to remove reference to the previous interim alternate repair criteria and provide reporting requirements specific for the Braidwood Unit 2 fall 2009 refueling outage (A2R14) and the subsequent operating cycle and for the Byron Unit 2 spring 2010 refueling outage (B2R15) and the subsequent operating cycle (Reference 9).

- Amendment Numbers 166 and 172 for Braidwood and Byron, respectively, to exclude portions of the tube below 16.95 inches from the top of the SG tubesheet from periodic SG inspections and plugging or repair and to remove reference to the previous interim alternate repair criteria and provide reporting requirements specific for the Braidwood Unit 2 spring 2011 refueling outage (A2R15) and the subsequent operating cycle and for the Byron Unit 2 fall 2011 refueling outage (B2R16) and the subsequent operating cycle (Reference 10).

Approval of this proposed license amendment request for the Braidwood and Byron permanent alternate repair criteria is requested by October 1, 2012, to support SG inspection activities during the Braidwood Unit 2 fall 2012 refueling outage (A2R16) and Byron Unit 2 spring 2013 refueling outage (B2R17). Once approved, the amendment will be implemented for Braidwood Unit 2 within 30 days and implemented for Byron Unit 2 prior to entering MODE 4 following SG inspections required by TS 5.5.9 beginning with the Unit 2 spring 2013 refueling outage (B2R17). The existing one-time alternate repair criteria amendments expire at the end of the current operating cycles.

2.0 DETAILED DESCRIPTION

Proposed changes to current Technical Specifications:

The current TS identified in this section are based on the Braidwood Station TS. Any differences between the current Braidwood and Byron TS are identified in braces with the specific Byron wording identified in brackets (e.g., "...during {Refueling Outage 14 [Byron: Refueling Outage 15]}").

TS 5.5.9.c currently 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 [Byron: Refueling Outage 16]} and the subsequent operating cycle, tubes with service-induced flaws located greater than 16.95 inches below the top of the tubesheet do not require plugging or repair. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 16.95 inches below the top of the tubesheet shall be plugged or repaired upon detection.

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

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

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

TS 5.5.9.c would be revised as follows, as noted in bold italic type.

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 [Byron: Refueling Outage 16]} and the subsequent operating cycle~~, tubes with service-induced flaws located greater than ~~16.95~~***14.01*** inches below the top of the tubesheet do not require plugging or repair. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to ~~16.95~~***14.01*** inches below the top of the tubesheet shall be plugged or repaired upon detection.

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

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

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

TS 5.5.9.d currently states:

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 [Byron: Refueling Outage 16]} 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. 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.

3. For Unit 1, if crack indications are found in any SG tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). For Unit 2 during {Refueling Outage 15 [Byron: Refueling Outage 16]} and the subsequent operating cycle, if crack indications are found in any SG tube from 16.95 inches below the top of the tubesheet on the hot leg side to 16.95 inches below the top of the tubesheet on the cold leg side, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less).

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

TS 5.5.9.d would be revised as follows, as noted in bold italic type.

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 [Byron: Refueling Outage 17]} and the subsequent operating cycle~~, portions of the tube below ~~16.95~~***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.

3. For Unit 1, if crack indications are found in any SG tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). For Unit 2~~ during {Refueling Outage 15 [Byron: Refueling Outage 16]} and the subsequent operating cycle~~, if crack indications are found in any SG tube from ~~16.95~~***14.01*** inches below the top of the tubesheet on the hot leg side to ~~16.95~~***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.

TS 5.6.9 currently states:

5.6.9 Steam Generator (SG) Tube Inspection Report

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

a. The scope of inspections performed on each SG,

b. Active degradation mechanisms found,

c. Nondestructive examination techniques utilized for each degradation mechanism,

d. Location, orientation (if linear), and measured sizes (if available) of service induced indications,

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

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

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

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

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

j. For Unit 2 following completion of an inspection performed in {Refueling Outage 15 [Byron: Refueling Outage 16]} (and any inspections performed in the subsequent operating cycle), the operational primary to secondary leakage rate observed (greater than three gallons per day) in each steam generator (if it is not practical to assign the leakage to an individual steam generator, the entire primary to secondary leakage should be conservatively assumed to be from one steam generator) during the cycle preceding the inspection which is the subject of the report, and

k. For Unit 2 following completion of an inspection performed in {Refueling Outage 15 [Byron: Refueling Outage 16]} (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 [Byron: Refueling Outage 16]} (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.

TS 5.6.9 would be revised as follows, as noted in bold italic type.

5.6.9 Steam Generator (SG) Tube Inspection Report

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

a. The scope of inspections performed on each SG,

b. Active degradation mechanisms found,

c. Nondestructive examination techniques utilized for each degradation mechanism,

d. Location, orientation (if linear), and measured sizes (if available) of service induced indications,

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

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

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

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

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

j. For Unit 2~~ following completion of an inspection performed in {Refueling Outage 15 [Byron: Refueling Outage 16]} (and any inspections performed in the subsequent operating cycle)~~, the operational primary to secondary leakage rate observed (greater than three gallons per day) in each steam generator (if it is not practical to assign the leakage to an individual steam generator, the entire primary to secondary leakage should be conservatively assumed to be from one steam generator) during the cycle preceding the inspection which is the subject of the report, ~~and~~

k. For Unit 2~~ following completion of an inspection performed in {Refueling Outage 15 [Byron: Refueling Outage 16]} (and any inspections performed in the subsequent operating cycle)~~, the calculated accident induced leakage rate from the portion of the tubes below ~~16.95~~***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~~ following completion of an inspection performed in {Refueling Outage 15 [Byron: Refueling Outage 16]} (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.

The marked-up TS pages provided in Attachments 2 and 3 indicate the proposed changes to the Braidwood Station and Byron Station TS, respectively.

3.0 BACKGROUND

Braidwood Station Unit 2 and Byron Station Unit 2 each contain four Westinghouse Model D5 recirculating pre-heater type SGs. Each SG contains 4,570 thermally treated Alloy-600 U-tubes that have an outer diameter of 0.750 inch with a 0.043 inch nominal wall thickness. The support plates are 1.12 inches thick stainless steel and have quatrefoil broached holes. The tubing within the tubesheet is hydraulically expanded throughout the full thickness of the tubesheet. The tubesheet is approximately 21 inches thick. Each unit operates on approximately 18-month fuel cycles.

The SG inspection scope is governed by TS 5.5.9; Nuclear Energy Institute (NEI) 97-06, "Steam Generator Program Guidelines," (Reference 11); Electric Power Research Institute (EPRI) 1013706, "Pressurized Water Reactor Steam Generator Examination Guidelines," (Reference 12); EPRI 1019038, "Steam Generator Integrity Assessment Guidelines," (Reference 13); EGC specific SG management program procedures; and the results of the degradation assessments required by the SG program. Criterion IX, "Control of Special Processes," of 10 CFR Part 50, Appendix B, requires in part that nondestructive testing be accomplished by qualified personnel using qualified procedures in accordance with the applicable criteria. The inspection techniques and equipment are capable of reliably detecting the known and potential specific degradation mechanisms applicable to the Braidwood and Byron Stations. The inspection techniques, essential variables and equipment are qualified to Appendix H, "Performance Demonstration for Eddy Current Examination," or Appendix I, "NDE System Measurement Uncertainties for Tube Integrity Assessments," of the EPRI PWR SG Examination Guidelines.

Catawba Nuclear Station, Unit 2, (Catawba) reported indication of cracking following nondestructive eddy current examination of the SG tubes during their fall 2004 outage. NRC Information Notice (IN) 2005-09, "Indications in Thermally Treated Alloy 600 Steam Generator Tubes and Tube-to-Tubesheet Welds," (Reference 14) provided industry notification of the Catawba issue. IN 2005-09 noted that Catawba reported crack like indications in the tubes approximately seven inches below the top of the hot leg tubesheet in one tube, and just above the tube-to-tubesheet welds in a region of the tube known as the tack expansion in several other tubes. Indications were also reported in the tube-end welds, also known as tube-to-tubesheet welds, which join the tube to the tubesheet.

EGC policies and programs require the use of applicable industry operating experience in the operation and maintenance of the Braidwood Station Unit 2 and Byron Station Unit 2 SGs. The experience at Catawba, as noted in IN 2005-09, shows the importance of monitoring all tube locations (such as bulges, dents, dings, and other anomalies from the manufacture of the SGs) with techniques capable of finding potential forms of degradation that may be occurring at these locations, as discussed in Generic Letter 2004-01, "Requirements for Steam Generator Tube Inspections," (Reference 15). Since the Braidwood Station Unit 2 and Byron Station Unit 2 contain Westinghouse Model D5 SGs that were fabricated with Alloy 600 thermally treated tubes similar to the Catawba Unit 2 Westinghouse Model D5 SGs, a potential exists for Braidwood Station Unit 2 and Byron Station Unit 2 to identify tube indications similar to those reported at Catawba within the hot leg tubesheet region if similar inspections are performed during the fall 2012 refueling outage for Braidwood Station Unit 2 and the spring 2013 refueling outage for Byron Station Unit 2.

Potential inspection plans for the tubes and tube welds underwent intensive industry discussions in March 2005. The indications in the Catawba SG tubes present three distinct issues with regard to the SG tubes at Braidwood Station Unit 2 and Byron Station Unit 2:

1) Indications in internal bulges and overexpansions within the hot leg tubesheet;

2) Indications at the elevation of the hot leg tack expansion transition; and

3) Indications in the tube-to-tubesheet welds and propagation of these indications into adjacent tube material.

Prior to each SG tube inspection, a degradation assessment, which includes a review of operating experience, is performed to identify degradation mechanisms that have a potential to be present in the Braidwood Station Unit 2 and Byron Station Unit 2 SGs. A validation assessment is also performed to verify that the eddy current techniques utilized are capable of detecting those flaw types that are identified in the degradation assessment. Based on the Catawba operating experience, Braidwood Station Unit 2 and Byron Station Unit 2 have revised the SG inspection plans for each inspection since the Braidwood Station Unit 2 spring 2005 refueling outage and the Byron Station Unit 2 fall 2005 refueling outage to include sampling of bulges and overexpansions within the tubesheet region on the hot leg side as well as the portion of the tubesheet required by TS 5.5.9 requirements in effect at the time of the inspection. The sample was based on the guidance contained in the EPRI PWR SG Examination Guidelines and TS 5.5.9. According to the EPRI PWR SG Examination Guidelines, the inspection plan is expanded, if necessary, due to confirmed degradation in the region required to be examined (i.e., a tube crack). The inspection plan was expanded according to EPRI PWR SG Examination Guidelines during the Braidwood Unit 2 spring 2008 outage (A2R13) and the Byron Station Unit 2 fall 2008 outage (B2R14) due to finding tube indications near the hot leg tube end. In each case, the inspection scope was increased to inspect 100% of the hot leg tube ends in each SG. Byron Station Unit 2 also expanded to 20% of the cold leg tube ends in each SG. No degradation was found in the cold leg tubes at Byron Station Unit 2.

During the Braidwood Unit 2 spring 2010 outage (A2R15), a 25% sample of bulges and overexpansions with the hot leg tubesheet region as well as a 25% sample of the tubes from the top of the hot leg tubesheet to 16.95 inches below the top of the hot leg tubesheet was inspected with a qualified plus-point probe in each SG. No tube degradation was found in these inspections.

During the Byron Unit 2 fall 2011 outage (B2R16), a 25% sample of bulges and overexpansions with the hot leg tubesheet region as well as a 25% of the tubes from the top of the hot leg tubesheet to 16.95 inches below the top of the hot leg tubesheet was inspected with a qualified plus-point probe in each SG. No tube degradation was found in these inspections.

As a result of these potential issues and the possibility of unnecessarily plugging or repairing tubes in the Braidwood Station Unit 2 and Byron Station Unit 2 SGs, EGC is proposing changes to TS 5.5.9 to perform SG tube inspection and plugging or repair of the safety significant portion of the tubes within the tubesheet. The safety significant portion of the tube within the tubesheet is known as the H* distance as measured from the top of the tubesheet.

4.0 SUMMARY OF LICENSING BASIS ANALYSIS (H* ANALYSES)

The Westinghouse analyses supporting this amendment request submittal are contained in the following two WCAPs:

- WCAP-17072-P, Revision 0 (as amended/supplemented), "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model D5)."
- WCAP-17330-P, Revision 1, "H*: Resolution of NRC Technical Issue Regarding Tubesheet Bore Eccentricity (Model F/Model D5)." This document is provided in this transmittal.

  Note that LTR-SGMP-11-58, "WCAP-17330-P, Rev. 1 Erratum" corrects a transcription error identified in Table 3-30 of WCAP-17330, Revision 1. This document is also provided in this transmittal.

The following table provides the list of Braidwood and Byron licensing basis documents for H*:

Document Number	Revision Number	Title	Reference Number
WCAP-17072-P	0	H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model D5)	1
WCAP-17330-P	1	H*: Resolution of NRC Technical Issue Regarding Tubesheet Bore Eccentricity (Model F/D5 Steam Generators)	2
LTR-SGMP-09-109 P-Attachment	0	Response to NRC Request for Additional Information on H*; RAI #4; Model F and Model D5 Steam Generators	16
LTR-SGMP-09-100 P-Attachment	1	Response to NRC Request for Additional Information on H*; Model F and Model D5 Steam Generators	17
LTR-SGMP-09-104-P Attachment	1	White Paper on Probabilistic Assessment of H*	18

Table of Braidwood and Byron licensing basis documents for H* (continued):

Document Number	Revision Number	Title	Reference Number
LTR-SGMP-10-78 P-Attachment	0	Effects of Tubesheet Bore Eccentricity and Dilation on Tube-to-Tubesheet Contact Pressure and Their Relative Importance to H*	19
LTR-SGMP-10-33 P-Attachment	0	H* Response to NRC Questions Regarding Tubesheet Bore Eccentricity	20
LTR-SGMP-09-111 P-Attachment	1	Acceptable Value of the Location of the Bottom of the Expansion Transition (BET) for Implementation of H*	21
LTR-SGMP-10-95 P-Attachment	1	H*: Alternate Leakage Calculation Methods for H* for Situations When Contact Pressure at Normal Operating Conditions Exceeds Contact Pressure at Accident Conditions	22
LTR-SGMP-11-58	0	WCAP-17330-P, Rev. 1 Erratum	23

In addition, the following correspondence is also applicable to the Braidwood and Byron permanent alternate repair criteria request:

- A March 28, 2011 letter from the NRC to Southern Nuclear Operating Company (Reference 24) documented the summary of a February 16, 2011 public meeting regarding steam generator tube inspection permanent alternate repair criteria. Enclosure 3 of the NRC letter provided technical NRC Staff questions developed at the meeting. Responses to these questions have been incorporated into WCAP-17330-P, Revision 1.

- Section 1.3 of WCAP-17330-P, Revision 1, identifies revisions in the report to address recommendations from the independent review of the H* analyses performed by MPR Associates. Related to the independent review, a May 26, 2011 letter from the NRC to Southern Nuclear Operating Company (Reference 25) included a presubmittal review request for additional information. The response to the NRC presubmittal review request is provided in Southern Nuclear Operating Company letter NL-11-1178 dated June 20, 2011 (Reference 26).

- In a letter dated January 12, 2012 (Reference 27), Duke Energy provided responses to the January 5, 2012, NRC request for additional information for the Catawba Nuclear Station. The Duke Energy responses included Westinghouse Letter LTR-SGMMP-11-28, Revision 0, "Response to USNRC RAI on Catawba Unit 2 Permanent H* Submittal, dated January 4, 2012 (Reference 28).

5.0 TECHNICAL EVALUATION

To determine the H* distance for the Braidwood Station Unit 2 and Byron Station Unit 2 SGs, an evaluation was performed to identify the safety significant portion of the tube within the tubesheet necessary to maintain structural and leakage integrity in both normal and accident conditions. Tube inspections will be performed to identify and plug or repair degradation in the safety significant portion of the tubes. The technical evaluation for the inspection and repair methodology is provided in the H* Analyses described in Section 4.0. The evaluation is based on the use of finite element model structural analysis and a bounding leak rate evaluation based on contact pressure between the tube and the tubesheet during normal and postulated accident conditions. The tubesheet region inspection criteria were developed for the Braidwood Station Unit 2 and Byron Station Unit 2 Model D5 SGs considering the most stringent loads associated with plant operation, including transients and postulated accident conditions. The tubesheet inspection criteria were selected to prevent tube pull out from the tubesheet due to axial end cap loads acting on the tube and to ensure that the accident induced leakage limits are not exceeded. The H* Analyses provides technical justification for limiting the inspection in the tubesheet expansion region to less than the full depth of the tubesheet.

The basis for determining the safety significant portion of the tube within the tubesheet is based upon evaluation and testing programs that quantified the tube-to-tubesheet radial contact pressure for bounding plant conditions as described in the H* Analyses. The tube-to-tubesheet radial contact pressure provides resistance to tube pull out and resistance to leakage during plant operation and transients.

Primary-to-secondary leakage from tube degradation in the tubesheet area is assumed to occur in several design basis accidents: main steam line break (SLB), locked rotor, locked rotor with a stuck open power operated relief valve (PORV), and control rod ejection. The main feedwater line break (FLB) radiological consequences were determined by the Updated Final Safety Analysis Report (UFSAR) to be bounded by the SLB event; therefore, no primary-to-secondary leakage was assumed for the FLB accident. The radiological dose consequences associated with this assumed leakage are evaluated to ensure that they remain within regulatory limits (e.g., 10 CFR Part 100, 10 CFR 50.67, GDC 19). The accident induced leakage performance criteria are intended to ensure the primary-to-secondary leak rate during any accident does not exceed the primary-to-secondary leak rate assumed in the accident analysis. Radiological dose consequences define the limiting accident condition for the H* justification.

The constraint that is provided by the tubesheet precludes tube burst for cracks within the tubesheet. The criteria for tube burst described in NEI 97-06 and draft NRC Regulatory Guide (RG) 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes," (Reference 29) are satisfied due to the constraint provided by the tubesheet. Through application of the tubesheet inspection scope as described below, the existing operating leakage limit provides assurance that excessive leakage (i.e., greater than accident analysis assumptions) will not occur. The assumed accident induced leak rate limit is 0.5 gallons per minute at room temperature (gpmRT) for the faulted SG and 0.218 gpmRT for each of the unfaulted SGs for accidents that assume a faulted SG.

These accidents are the SLB and the locked rotor with a stuck open PORV. The assumed accident induced leak rate limit for accidents that do not assume a faulted SG is 1.0 gpmRT for all SGs. These accidents are the locked rotor and control rod ejection. The TS operational leak rate limit is 150 gallons per day (gpd) (0.104 gpmRT) through any one SG. Consequently, there is sufficient margin between accident leakage and allowable operational leakage. The maximum accident leak rate ratio for the Model D5 design SGs is 1.93 as indicated in WCAP-17072-P, Revision 0, Table 9-7. However, EGC will use the more conservative value of 3.11 accident leak rate ratio specific to Byron Unit 2 and Braidwood Unit 2 identified in Westinghouse Letter LTR-SGMP-09-100 P-Attachment, Table RAI24-2. This results in sufficient margin between the conservatively estimated accident leakage and the allowable accident leakage (0.5 gpmRT).

Plant-specific operating conditions are used to generate the overall leakage factor ratios that are used in the condition monitoring (CM) and operational assessments. The plant-specific data provide the initial conditions for application of the transient input data. The results of the analysis of the plant-specific inputs to determine the plant specific leak rate ratios.

The leak rate ratio (accident induced leak rate to operational leak rate) is directly proportional to the change in differential pressure and inversely proportional to the dynamic viscosity. Since dynamic viscosity decreases with an increase in temperature, an increase in temperature results in an increase in leak rate.

For both the SLB and FLB events, a plant cooldown event would occur and the subsequent temperatures in the reactor coolant system (RCS) would not be expected to exceed the temperatures at plant no load conditions. However, per Westinghouse Letter LTR-SGMP-09-100 P-Attachment, Revision 1, the FLB transient was evaluated as a heatup event. The resulting leak rate ratio for the SLB and FLB events is 3.11, which is the bounding value for Byron Unit 2 and Braidwood Unit 2 as evaluated in LTR-SGMP-09-100 P-Attachment, Revision 1.

The other design basis accidents, such as the postulated locked rotor events and the control rod ejection event, are conservatively modeled using the design specification transients that result in increased temperatures in the SG hot and cold legs for a period of time. As previously noted, dynamic viscosity decreases with increasing temperature. Therefore, leakage would be expected to increase due to decreasing viscosity and increasing differential pressure for the duration of time that there is a rise in RCS temperature. For transients other than a SLB and FLB, the length of time that a plant with Model D5 SGs will exceed the normal operating differential pressure across the tubesheet is less than 30 seconds. As the accident induced leakage performance criteria is defined in gallons per minute, the leak rate for a locked rotor event can be integrated over a minute for comparison to the limit. Time integration permits an increase in acceptable leakage during the time of peak pressure differential by approximately a factor of two because of the short duration (less than 30 seconds) of the elevated pressure differential. This translates into an effective reduction in the leakage factor by the same factor of two for the locked rotor event. Therefore, for the locked rotor event, the leakage factor of 1.54 for Braidwood Station Unit 2 and Byron Station Unit 2 is adjusted downward to a leakage factor of 0.77. Similarly, for the control rod ejection event, the duration of the elevated pressure differential is less than 10 seconds.

Thus, the peak leakage factor is reduced by a factor of six, from 2.54 to 0.42 (LTR-SGMP-09-100 P-Attachment, Table RAI24-2). Due to the short duration of the transients above NOP differential, no leakage factor is required for the locked rotor and control rod ejection events (i.e., the leakage factor is under 1.0 for both transients). Additionally, the impact of the proposed Measurement Uncertainty Recapture (MUR) on the leak rate and H* distance has been evaluated, and it has been concluded that no changes are required.

The plant transient response following a full power double-ended main feedwater line rupture corresponding to "best estimate" initial conditions and operating characteristics indicates that the transient for a Model D5 steam generator exhibits a cooldown characteristic instead of a heat-up transient as generally presented in steam generator design transients and in the UFSAR Chapter 15.0 safety analysis. The use of either the component design specification transient or the UFSAR Chapter 15.0 safety analysis for leakage analysis for FLB is overly conservative because:

- The assumptions on which the FLB design transient is based are specifically intended to establish a conservative structural (fatigue) design basis for reactor coolant system components; however, H* does not involve component structural and fatigue issues. The best estimate transient is considered more appropriate for use in the H* leakage calculations.

- For the Model D5 steam generator, the FLB transient curve (WCAP-17072-P, Revision 0, Figure 9-6) the maximum RCS temperature can exceed the saturation temperature which is predicted to occur by the worst-case FLB heatup Chapter 15 Safety Analysis Transient response.

- The assumptions on which the FLB safety analysis is based are specifically intended to establish a conservative basis for minimum auxiliary feedwater (AFW) capacity requirements and combines worst case assumptions which are exceptionally more severe when the FLB occurs inside containment. For example, environmental errors that are applied to reactor trip and engineered safety feature actuation would be less severe. This would result in much earlier reactor trip and greatly increase the steam generator liquid mass available to provide cooling to the RCS.

A SLB event would have similarities to a FLB except that the break flow path would include the secondary separators, which could only result in an increased initial cooldown (because of retained liquid inventory available for cooling) when compared to the FLB transient. A SLB could not result in more limiting temperature conditions than a FLB.

In accordance with plant operating procedures, the operator would take action following a high-energy secondary line break to stabilize the RCS conditions. The expected response for a SLB or FLB with credited operator action is to stop the system cooldown through isolation of the faulted SG and control temperature by the AFW system. Steam pressure control would be established by either the SG safety valves or control systems (steam dump or atmospheric relief valves). For any of the steam pressure control operations, the maximum temperature would be approximately the no load temperature and would be well below normal operating temperature.

Since the best estimate FLB transient temperature considered in WCAP-17072-P, Revision 0, would not be expected to exceed the normal operating temperature, the viscosity ratio for the FLB transient is set to 1.0.

However, the "figure of merit" in the technical specification performance criterion is "the leakage rate assumed in the accident analysis" and that a FLB heatup event is part of the current licensing basis for certain plants in the H* fleet. Therefore, to ensure that there is sufficient margin between the accident leakage and operational leakage during a postulated FLB as required by the plant Technical Specifications and to ensure that the implementation of the H* criterion remains within the current licensing basis, an adjustment to the leakage factors provided in Table 9-7 of WCAP-17072-P, Revision 0, has been made that accommodates the design specification FLB heatup event (LTR-SGMP-09-100 P-Attachment, Table RAI24-2). The use of temperatures from this transient is judged to be conservative. The evaluation provided in LTR-SGMP-09-100 P-Attachment provides adjustments to the leak rate factors described in WCAP-17072-P, Revision 0. For Byron Unit 2 and Braidwood Unit 2, the leak rate factor is increased from 1.93 to 3.11.

The leakage factor of 1.93 for Braidwood Station Unit 2 and Byron Station Unit 2 for a postulated SLB/FLB has been calculated as shown in Revised Table 9-7 of WCAP-17072, Revision 0. However, EGC will apply a factor of 3.11 to the normal operating leakage associated with the tubesheet expansion region in the condition monitoring (CM) and operational assessment (OA). The leakage factor of 3.11 is specific to the Byron Unit 2 and Braidwood Unit 2 SGs, both hot and cold legs, in Revised Table RAI24-2 of LTR-SGMP-09-100 P-Attachment. Specifically, for the CM assessment, the component of leakage from the prior cycle from below the H* distance will be multiplied by a factor of 3.11 and added to the total leakage from any other source and compared to the allowable accident induced leakage limit. For the OA, the difference in the leakage between the allowable leakage and the accident induced leakage from sources other than the tubesheet expansion region will be divided by 3.11 and compared to the observed operational leakage. An administrative operational leakage limit will be established as necessary to ensure that the accident induced leakage limit is not exceeded (Reference Summary of Regulatory Commitments in Attachment 6 to this letter).

An assessment of the operational leakage limit, the 3.11 leakage factor and the accident induced leakage limit was performed and concluded that there is sufficient margin to maintain the current TS operational limit of 150 gpd (0.104 gpmRT). If the entire TS operational limit is assumed to be associated with the tube area below the H* distance, the maximum accident induced leakage from that source would be 0.324 gpmRT, which is less than the 0.5 gpmRT accident leakage limit (i.e., 0.104 gpmRT X 3.11). Therefore, there is margin to have leakage from other sources which is greater than the TS operational limit of 150 gpd (0.104 gpmRT). Similarly, if the entire current TS operational limit 150 gpd (0.104 gpmRT) is assumed to be from sources other than the area below the H* distance, the amount of leakage that is acceptable from the area below the H* distance is 0.127 gpmRT (i.e., (0.5-0.104)/3.11), which is greater than the current 150 gpd (0.104 gpmRT) TS operational leakage limit. The treatment of the operational leakage limits, leakage below the H* distance where the 3.11 leakage factor is applied, and leakage from other sources will ensure that the accident induced leakage limit is not exceeded or an administrative operational leakage limit will be established (Reference Summary of Regulatory Commitments in Attachment 6 to this letter).

The feedwater line break heat-up transient definition is not a concern for the H* structural analysis. As shown in Figure 4-1 through Figure 4-6 of WCAP-17330-P, Revision 1, the FLB heatup event tube to tubesheet contact pressures are significantly higher than the SLB and NOP condition contact pressures. Additionally, the FLB cooldown event contact pressures would be similar to the SLB event which is also a cooldown event. Therefore, the FLB heatup event would not be a driving factor to limit the H* depth within the structural analysis.

Application of the supporting structural analysis and leakage evaluation is interpreted to constitute a redefinition of the primary-to-secondary pressure boundary. WCAP-17072-P, Revision 0, and WCAP-17330-P, Revision 1, redefines the primary pressure boundary. The tube to tubesheet weld no longer functions as a portion of this boundary. The hydraulic expansion of the tube into the tubesheet over the H* distance now functions as the primary pressure boundary in the area of the tube and tubesheet, maintaining the structural and leakage integrity over the full range of SG operating conditions, including the most limiting accident conditions. The evaluation in WCAP-17072-P, Revision 0, determined that degradation in tubing below the H* value of 13.8 inches from the top of the tubesheet does not require inspection and plugging or repair. The 13.8 inch value of H* is based on normal operating pressure as being the limiting condition and consequently this H* value is based on 95/50 whole plant analysis. Table 5-1 of WCAP-17330-P, Revision 1, determined the 95/95 whole bundle depth of 14.01 inches from the top of the tubesheet for plants with Model D5 Steam Generators which includes Braidwood Unit 2 and Byron Unit 2. Exelon is therefore using the value of 14.01 inches. As such, the Braidwood Unit 2 and Byron Unit 2 inspection programs provide a high level of confidence that the structural and leakage criteria are maintained during normal operating and accident conditions.

WCAP-17072-P, Revision 0, Section 9.8, provides a review of leak rate susceptibility to tube slippage and concluded that the tubes are fully restrained against motion under very conservative design and analysis assumptions such that tube slippage is not a credible event for any tube in the bundle. However, in response to an NRC request, EGC commits to monitor for tube slippage as part of the SG tube inspection program for Braidwood Station Unit 2 and Byron Station Unit 2 (Reference Summary of Regulatory Commitments in Attachment 6 to this letter).

During the Byron Unit 2 Cycle 12 refueling outage (September 2005), all tubes were screened to identify if there were any hot leg or cold leg tubes that did not contain fully expanded tubes. As a result of this screening, one tube in the 2D steam generator was identified as not being hydraulically expanded into the full depth of the tubesheet. The tube was removed from service. During the Braidwood Unit 2 Cycle 12 refueling outage (September 2006), all tubes were screened to identify if there were any hot leg or cold leg tubes that did not contain fully expanded tubes. As a result of this screening, all tubes were confirmed to contain hydraulic expansions into the full depth of the tubesheet. Therefore, all current inservice tubes in the Byron and Braidwood Unit 2 SG's contain hydraulic expansions to the full depth of the tubesheet.

In addition, as a condition for approving the one-time alternate repair criteria for Byron and Braidwood Unit 2 (Reference 9), the NRC staff requested that Exelon perform a validation of the tube expansion from the top of the tubesheet to the beginning of the expansion transition (BET) to determine if there are any significant deviations that would invalidate assumptions in WCAP-17072-P, Revision 0. Exelon completed the one-time validation of the BET locations for all tubes at Byron and Braidwood Unit 2. Based on the data review, there were no significant BET deviations found.

6.0 REGULATORY EVALUATION

6.1 Applicable Regulatory Requirements/Criteria

General Design Criteria (GDC) 1, 2, 4, 14, 30, 31, and 32 of 10 CFR 50, Appendix A, define requirements for the reactor coolant pressure boundary (RCPB) with respect to structural and leakage integrity.

GDC 19 of 10 CFR 50, Appendix A, defines requirements for the control room and for the radiation protection of the operators working within it. Accidents involving the leakage or burst of SG tubing comprise a challenge to the habitability of the control room.

10 CFR 50, Appendix B, establishes quality assurance requirements for the design, construction, and operation of safety related components. The pertinent requirements of this appendix apply to all activities affecting the safety related functions of these components. These requirements are described in Criteria IX, XI, and XVI of Appendix B and include control of special processes, inspection, testing, and corrective action.

10 CFR 100 establishes reactor site criteria, with respect to the risk of public exposure to the release of radioactive fission products. Accidents involving leakage or tube burst of SG tubing may comprise a challenge to containment and therefore involve an increased risk of radioactive release.

On September 8, 2006, the NRC approved a license amendment to fully implement an Alternative Source Term (AST), pursuant to 10 CFR 50.67 (Reference 30). 10 CFR 50.67 establishes limits on the accident source term used in design basis radiological consequence analyses with regard to radiation exposure to members of the public and to control room occupants. With the application of AST methodology to Braidwood Station and Byron Station, bounding design basis accidents analyzed in the UFSAR specify maximum dose in Total Effective Dose Equivalent (TEDE) criteria specified in 10 CFR 50.67 using the radiological source term criteria in RG 1.183. For non-bounding transients and other accidents analyzed in the UFSAR that have not been converted to use AST, the maximum dose to the whole body and the thyroid that an individual at the site boundary can receive for two hours during an accident is specified in 10 CFR 100. Doses to Control Room operators are as described in GDC 19.

Under 10 CFR 50.65, the Maintenance Rule, licensees classify SGs as risk significant components because they are relied upon to remain functional during and after design basis events. SGs are to be monitored under 10 CFR 50.65(a)(2) against industry established performance criteria. Meeting the performance criteria of NEI 97-06, Revision 3, provides reasonable assurance that the SG tubing remains capable of fulfilling its specific safety function of maintaining the reactor coolant pressure boundary. The NEI 97-06, Revision 3, SG performance criteria are:

- All in-service SG tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, cooldown, 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 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 loads.

- 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 1 gpm per SG, except for specific types of degradation at specific locations when implementing alternate repair criteria as documented in the Steam Generator Program Technical Specifications. (The Braidwood and Byron Station Technical Specifications require that the primary-to-secondary leakage not exceed a total of 1 gpm for all SGs.)

- The RCS operational primary-to-secondary leakage through any one SG shall be limited to 150 gallons per day.

The safety significant portion of the tube is the length of tube that is engaged in the tubesheet secondary face that is required to maintain structural and leakage integrity over the full range of SG operating conditions, including the most limiting accident conditions. The evaluation in WCAP-17330-P, Revision 1, determined that degradation in tubing below 14.01 inches from the top of the tubesheet portion of the tube does not require inspection and plugging or repair. As such, the Braidwood Unit 2 and Byron Unit 2 inspection programs provide a high level of confidence that the structural and leakage criteria are maintained during normal operating and accident conditions.

6.2 Precedents

The NRC has approved a similar license amendment request to revise TS for permanent alternate repair criteria as follows:

> Letter from J. Thompson (U. S. NRC) to J. R. Morris (Duke Energy Carolinas, LLC), "Catawba Nuclear Station, Units 1 and 2, Issuance of Amendments Regarding Technical Specifications Amendments for Permanent Alternate Repair Criteria for Steam Generator Tubes (TAC Nos. ME6670 and ME6671)," dated March 12, 2012.

A similar submittal for permanent alternate repair criteria was submitted as follows:

> Letter from J. A. Price (Dominion) to U. S. NRC, "Surry Power Station Units 1 and 2 License Amendment Request Permanent Alternate Repair Criteria for Steam Generator Tube Inspection and Repair," dated July 28, 2011.

6.3 No Significant Hazards Consideration

This amendment request proposes to revise Technical Specifications (TS) 5.5.9, "Steam Generator (SG) Program," to exclude portions of the tubes within the tubesheet from periodic steam generator (SG) inspections and plugging or repair. In addition, this amendment request proposes to revise TS 5.6.9, "Steam Generator (SG) Tube Inspection Report," to remove reference to previous interim alternate repair criteria and provide reporting requirements specific to the permanent alternate criteria. Application of the structural analysis and leak rate evaluation results, to exclude portions of the tubes from inspection and repair is interpreted to constitute a redefinition of the primary-to-secondary pressure boundary.

The proposed changes define the safety significant portion of the tube that must be inspected, plugged, or repaired. A justification has been developed by Westinghouse Electric Company LLC, as documented in WCAP-17330-P, "H*: Resolution of NRC Technical Issue Regarding Tubesheet Bore Eccentricity," Revision 1, to identify the specific inspection depth below which any type of axial or circumferential primary water stress corrosion cracking can be shown to have no impact on Nuclear Energy Institute (NEI) 97-06, Revision 3, "Steam Generator Program Guidelines," performance criteria.

EGC has evaluated for Braidwood Station and Byron Station whether or not a significant hazards consideration is involved with the proposed amendment by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

Criteria

1. Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No.

   The previously analyzed accidents are initiated by the failure of plant structures, systems, or components. The proposed change that alters the steam generator (SG) inspection and reporting criteria does not have a detrimental impact on the integrity of any plant structure, system, or component that initiates an analyzed event. The proposed change will not alter the operation of, or otherwise increase the failure probability of any plant equipment that initiates an analyzed accident.

   Of the various accidents previously evaluated, the proposed changes only affect the steam generator tube rupture (SGTR), postulated steam line break (SLB), feedwater line break (FLB), locked rotor and control rod ejection accident evaluations. Loss-of-coolant accident (LOCA) conditions cause a compressive axial load to act on the tube. Therefore, since the LOCA tends to force the tube into the tubesheet rather than pull it out, it is not a factor in this amendment request. Another faulted load consideration is a safe shutdown earthquake (SSE); however, the seismic analysis of Model D5 SGs has shown that axial loading of the tubes is negligible during an SSE.

   During the SGTR event, the required structural integrity margins of the SG tubes and the tube-to-tubesheet joint over the H* distance will be maintained. Tube rupture in tubes with cracks within the tubesheet is precluded by the constraint provided by the presence of the tubesheet and the tube-to-tubesheet joint. Tube burst cannot occur within the thickness of the tubesheet. The tube-to-tubesheet joint constraint results from the hydraulic expansion process, thermal expansion mismatch between the tube and tubesheet, and from the differential pressure between the primary and secondary side, and tubesheet rotation. Based on this design, the structural margins against burst, as discussed in draft Regulatory Guide (RG) 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes," and TS 5.5.9, are maintained for both normal and postulated accident conditions.

   The proposed change has no impact on the structural or leakage integrity of the portion of the tube outside of the tubesheet. The proposed change maintains structural and leakage integrity of the SG tubes consistent with the performance criteria of TS 5.5.9. Therefore, the proposed change results in no significant increase in the probability of the occurrence of a SGTR accident.

   At normal operating pressures, leakage from tube degradation below the proposed limited inspection depth is limited by the tube-to-tubesheet crevice. Consequently, negligible normal operating leakage is expected from degradation below the inspected depth within the tubesheet region. The consequences of an SGTR event are not affected by the primary-to-secondary leakage flow during the event as primary-to-secondary leakage flow through a postulated tube that has been pulled out of the tubesheet is essentially equivalent to a severed tube. Therefore, the proposed change does not result in a significant increase in the consequences of a SGTR.

Primary-to-secondary leakage from tube degradation in the tubesheet area during operating and accident conditions is restricted due to contact of the tube with the tubesheet. The leakage is modeled as flow through a porous medium through the use of the Darcy equation. The leakage model is used to develop a relationship between operational leakage and leakage at accident conditions that is based on differential pressure across the tubesheet and the viscosity of the fluid. A leak rate ratio was developed to relate the leakage at operating conditions to leakage at accident conditions. Since the fluid viscosity is based on fluid temperature and it is shown that for the most limiting accident, the fluid temperature does not exceed the normal operating temperature and therefore the viscosity ratio is assumed to be 1.0. Therefore, the leak rate ratio is a function of the ratio of the accident differential pressure and the normal operating differential pressure.

The leakage factor of 1.93 for Braidwood Station Unit 2 and Byron Station Unit 2, for a postulated SLB/FLB, has been calculated as shown in Table 9-7 of WCAP-17072-P, Revision 0. However, EGC Braidwood Station Unit 2 and Byron Station Unit 2 will apply a factor of 3.11 as determined by Westinghouse evaluation LTR-SGMP-09-100 P-Attachment, Revision 1, to the normal operating leakage associated with the tubesheet expansion region in the condition monitoring (CM) and operational assessment (OA). The leakage factor of 3.11 applies specifically to Byron Unit 2 and Braidwood Unit 2, both hot and cold legs, in Table RAI24-2 of LTR-SGMP-09-100 P-Attachment, Revision 1. Through application of the limited tubesheet inspection scope, the existing operating leakage limit provides assurance that excessive leakage (i.e., greater than accident analysis assumptions) will not occur. The assumed accident induced leak rate limit is 0.5 gallons per minute at room temperature (gpmRT) for the faulted SG and 0.218 gpmRT for each of the unfaulted SGs for accidents that assume a faulted SG. These accidents are the SLB and the locked rotor with a stuck open PORV. The assumed accident induced leak rate limit for accidents that do not assume a faulted SG is 1.0 gpmRT for all SGs. These accidents are the locked rotor and control rod ejection.

No leakage factor will be applied to the locked rotor or control rod ejection transients due to their short duration, since the calculated leak rate ratio is less than 1.0.

The TS 3.4.13 operational leak rate limit is 150 gallons per day (gpd) (0.104 gpmRT) through any one SG. Consequently, there is sufficient margin between accident leakage and allowable operational leakage. The maximum accident leak rate ratio for the Model D5 design SGs is 1.93 as indicated in WCAP-17072-P, Revision 0, Table 9-7. However, EGC will use the more conservative value of 3.11 accident leak rate ratio for the most limiting SG model design identified in Table RAI24-2 of LTR-SGMP-09-100 P-Attachment Revision 1. This results in significant margin between the conservatively estimated accident leakage and the allowable accident leakage (0.5 gpmRT)

For the CM assessment, the component of leakage from the prior cycle from below the H* distance will be multiplied by a factor of 3.11 and added to the total leakage from any other source and compared to the allowable accident induced leakage limit. For the OA, the difference in the leakage between the allowable 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.

Based on the above, the performance criteria of NEI-97-06, Revision 3, and draft RG 1.121 continue to be met and the proposed change does not involve a significant increase in the probability or consequences of the applicable accidents previously evaluated.

2. Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

   Response: No.

   The proposed change does not introduce any changes or mechanisms that create the possibility of a new or different kind of accident. Tube bundle integrity is expected to be maintained for all plant conditions upon implementation of the permanent alternate repair criteria. The proposed change does not introduce any new equipment or any change to existing equipment. No new effects on existing equipment are created nor are any new malfunctions introduced.

   Therefore, based on the above evaluation, the proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the proposed change involve a significant reduction in a margin of safety?

   Response: No.

   The proposed change defines the safety significant portion of the SG tube that must be inspected and repaired. WCAP-17072-P, Revision 0, as modified by WCAP-17330-P, Revision 1, identifies the specific inspection depth below which any type tube degradation has no impact on the performance criteria in NEI 97-06, Revision 3, "Steam Generator Program Guidelines."

The proposed change that alters the SG inspection and reporting criteria maintains the required structural margins of the SG tubes for both normal and accident conditions. NEI 97-06, and draft RG 1.121 are used as the bases in the development of the limited tubesheet inspection depth methodology for determining that SG tube integrity considerations are maintained within acceptable limits. Draft RG 1.121 describes a method acceptable to the NRC for meeting General Design Criteria (GDC) 14, "Reactor Coolant Pressure Boundary," GDC 15, "Reactor Coolant System Design," GDC 31, "Fracture Prevention of Reactor Coolant Pressure Boundary," and GDC 32, "Inspection of Reactor Coolant Pressure Boundary," by reducing the probability and consequences of a SGTR. Draft RG 1.121 concludes that by determining the limiting safe conditions for tube wall degradation, the probability and consequences of a SGTR are reduced. This draft RG uses safety factors on loads for tube burst that are consistent with the requirements of Section III of the American Society of Mechanical Engineers (ASME) Code.

For axially oriented cracking located within the tubesheet, tube burst is precluded due to the presence of the tubesheet. For circumferentially oriented cracking, WCAP-17072-P, Revision 0, as modified by WCAP-17330-P, Revision 1, defines a length of degradation-free expanded tubing that provides the necessary resistance to tube pullout due to the pressure induced forces, with applicable safety factors applied. Application of the limited hot and cold leg tubesheet inspection criteria will preclude unacceptable primary-to-secondary leakage during all plant conditions. The methodology for determining leakage as described in WCAP-17072-P, Revision 0, as modified by LTR-SGMP-09-100 P-Attachment shows that significant margin exists between an acceptable level of leakage during normal operating conditions that ensures meeting the SLB accident-induced leakage assumption and the TS leakage limit of 150 gpd.

Based on the above, it is concluded that the proposed changes do not result in any reduction in a margin of safety.

6.4 Conclusion

The safety significant portion of the tube is the length of the tube that is engaged within the tubesheet to the top of the tubesheet (secondary face) that is required to maintain structural and leakage integrity over the full range of SG operating conditions, including the most limiting accident conditions. The H* Analyses determined that the degradation in tubing below the safety significant portion of the tube does not require inspection, plugging, or repair. WCAP-17072-P, Revision 0, and WCAP-17330-P, Revision 1, serve as the basis for the tubesheet inspection criteria known as the H* criteria, which is intended to ensure the primary to secondary leak rate during any accident does not exceed the leak rate assumed in the accident analysis.

Based on the considerations above, EGC concludes that the proposed amendment presents no significant hazards consideration under the standards set forth in 10 CFR 50.92(c) and, accordingly, a finding of "no significant hazards consideration" is justified.

7.0 ENVIRONMENTAL CONSIDERATION

EGC has evaluated the proposed amendment for environmental considerations. The review has resulted in the determination that the proposed amendment would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, and would change an inspection or surveillance requirement. However, the proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

8.0 REFERENCES

1) Westinghouse Electric Company LLC, WCAP-17072-P, Revision 0, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model D5)," May 2009. (Proprietary)

2) Westinghouse Electric Company LLC, WCAP-17330-P, Revision 1, "H*: Resolution of NRC Technical Issue Regarding Tubesheet Bore Eccentricity (Model F/ Model D5)," June 2011. (Proprietary)

3) Letter from G. F. Dick (USNRC) to C. M. Crane (EGC), "Braidwood Station, Units 1 and 2 – Issuance of Exigent Amendments Re: Revision of Scope of Steam Generator Inspections For Unit 2 Refueling Outage 11 (TAC Nos. MC6686 and MC6687)," dated April 25, 2005. (Braidwood Amendment 135)

4) Letter from J. B. Hopkins (USNRC) to C. M. Crane (EGC), "Byron Station, Unit 2 – Issuance of Amendment (TAC No. MC7219)," dated September 19, 2005. (Byron Amendment 144)

5) Letter from R. F. Kuntz (USNRC) to C. M. Crane (EGC), "Braidwood Station, Unit No. 2 – Issuance of Amendments Re: Steam Generator Inspection Criteria (TAC No. MC8969)," dated October 24, 2006. (Braidwood Amendment 141)

6) Letter from R. F. Kuntz (USNRC) to C. M. Crane (EGC), "Byron Station, Unit Nos. 1 and 2, and Braidwood Station, Units Nos. 1 and 2 – Issuance of Amendments Re: Steam Generator Tube Surveillance Program (TAC Nos. MC8966, MC8967, MC8968, and MC8969)," dated March 30, 2007. (Byron Amendment 150/ Braidwood Amendment 144)

7) Letter from M. J. David (USNRC) to C. G. Pardee (EGC), "Braidwood Station, Units 1 and 2 – Issuance of Amendments Re: Revision to Technical Specifications For the Steam Generator Program (TAC Nos. MD8158 and MD8159)," dated April 18, 2008. (Braidwood Amendment 150)

8) Letter from M. J. David (USNRC) to C. G. Pardee (EGC), "Byron Station, Unit Nos. 1 and 2 – Issuance of Amendments Re: Revision to Technical Specifications For the Steam Generator Program (TAC Nos. MD9018 and MD9019)," dated October 1, 2008. (Byron Amendment 158)

9) Letter from M. J. David (USNRC) to C. G. Pardee (EGC), "Braidwood Station, Units 1 and 2, and Byron Station, Unit Nos. 1 and 2 – Issuance of Amendments Re: Revision to Technical Specifications For the Steam Generator Program (TAC Nos. ME1613, ME1614, ME1615, and ME1616)," dated October 16, 2009. (Braidwood Amendment 161/Byron Amendment 166)

10) Letter from N. J. DiFrancesco (USNRC) to M. J. Pacilio (EGC), "Braidwood Station, Units 1 and 2 and Byron Station, Unit Nos. 1 and 2 – Issuance of Amendments Re: Changes to Technical Specification Sections 5.5.9, "Steam Generator (SG) Program" and 5.6.9, "Steam Generator (SG) Tube Inspection Report," (TAC Nos. ME5198, ME5199, ME5200, and ME5201)," dated April 13, 2011. (Braidwood Amendment 166/Byron Amendment 172)

11) NEI 97-06, "Steam Generator Program Guidelines," Revision 3, January 2011.

12) EPRI 1013706, "Pressurized Water Reactor Steam Generator Examination Guidelines," Revision 7, October 2007.

13) EPRI 1019038, "Steam Generator Integrity Assessment Guidelines," Revision 3, November 2009.

14) NRC Information Notice 2005-09, "Indications in Thermally Treated Alloy 600 Steam Generator Tubes and Tube-to-Tubesheet Welds," April 7, 2005.

15) NRC Generic Letter 2004-01, "Requirements for Steam Generator Tube Inspections," August 30, 2004.

16) Westinghouse Letter LTR-SGMP-09-109 P-Attachment, Revision 0, "Response to NRC Request for Additional Information on H*; RAI #4; Model F and Model D5 Steam Generators," dated August 25, 2009. (Proprietary)

17) Westinghouse Letter LTR-SGMP-09-100 P-Attachment, Revision 1, "Response to NRC Request for Additional Information on H*; Model F and Model D5 Steam Generators," dated September 7, 2010. (Proprietary)

18) Westinghouse Letter LTR-SGMP-09-104-P Attachment, Revision 1, "White Paper on Probabilistic Assessment of H*," dated August 13, 2009. (Proprietary)

19) Westinghouse Letter LTR-SGMP-10-78 P-Attachment, Revision 0, "Effects of Tubesheet Bore Eccentricity and Dilation on Tube-to-Tubesheet Contact Pressure and Their Relative Importance to H*," dated September 7, 2009. (Proprietary)

20) Westinghouse Letter LTR-SGMP-10-33 P-Attachment, Revision 0, "H* Response to NRC Questions Regarding Tubesheet Bore Eccentricity," dated September 13, 2010. (Proprietary)

21) Westinghouse Letter LTR-SGMP-09-111 P-Attachment, Revision 1, "Acceptable Value of the Location of the Bottom of the Expansion Transition (BET) for Implementation of H*," dated September 1, 2010. (Proprietary)

22) Westinghouse Letter LTR-SGMP-10-95 P-Attachment, Revision 1, "H*: Alternate Leakage Calculation Methods for H* for Situations When Contact Pressure at Normal Operating Conditions Exceeds Contact Pressure at Accident Conditions," dated September 2010. (Proprietary)

23) LTR-SGMP-11-58, "WCAP-17330-P, Rev. 1 Erratum," dated July 6, 2011.

24) Letter from NRC to Southern Nuclear Operating Company, Inc., "Vogtle Electric Generating Plant Units 1 and 2 – Summary of February 16, 2011 Meeting with Southern Nuclear Operating Company, Inc. and Westinghouse on Technical Issues Regarding Steam Generator Tube Inspection Permanent Alternate Repair Criteria (ADAMS Accession No. ML110660648)," dated March 28, 2011.

25) Letter from NRC to Southern Nuclear Operating Company, Inc., "Vogtle Electric Generating Plant Units 1 and 2 – Presubmittal Consideration of Steam Generator Alternative Repair Criteria Requirements Request for Additional Information, (ADAMS Accession No. ML11140A099)," dated May 26, 2011.

26) Letter from Southern Nuclear Operating Company, Inc., to NRC, "Vogtle Electric Generating Plant – Response to Presubmittal Consideration of Steam Generator Alternative Repair Criteria Requirements Request for Additional Information," dated June 20, 2011.

27) Letter from J. R. Morris (Duke Energy) to U. S. Nuclear Regulatory Commission Regarding Response to Requests for Additional Information Associated with License Amendment Request to Revise TS for Permanent Alternate Repair Criteria, dated January 12, 2012.

28) Westinghouse Letter LTR-SGMMP-11-28, "Response to USNRC RAI on Catawba Unit 2 Permanent H* Submittal," dated January 4, 2012.

29) Draft NRC Regulatory Guide 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes," issued for comment August 1976.

30) Letter from R. F. Kuntz (NRC) to C. M. Crane (EGC), "Byron Station, Unit Nos. 1 and 2, and Braidwood Station, Unit Nos. 1 and 2 - Issuance of Amendments Re: Alternative Source Term," dated September 8, 2006.

ATTACHMENT 2
Markup of Technical Specifications Pages for Braidwood Station, Units 1 and 2

Braidwood Station, Units 1 and 2

Facility Operating License Nos. NPF-72 and NPF-77

Proposed Technical Specifications Pages for Braidwood Station, Units 1 and 2

5.5-8
5.5-9
5.5-10
5.6-7

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

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

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

c. Provisions for SG tube repair criteria.

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

14.01

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

14.01

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

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

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

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. For Unit 2 ~~during Refueling Outage 15 and the subsequent operating cycle~~, portions of the tube below ~~16.95~~ 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 ~~during Refueling Outage 15 and the subsequent operating cycle~~, if crack indications are found in any SG tube from 14.01 ~~16.95~~ inches below the top of the tubesheet on the hot leg side to 14.01 ~~16.95~~ inches below the top of the tubesheet on the cold leg side, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less).

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

e. Provisions for monitoring operational primary to secondary LEAKAGE.

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

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

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

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

5.6 Reporting Requirements

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

j. For Unit 2 ~~following completion of an inspection performed in Refueling Outage 15 (and any inspections performed in the subsequent operating cycle)~~, the operational primary to secondary leakage rate observed (greater than three gallons per day) in each steam generator (if it is not practical to assign the leakage to an individual steam generator, the entire primary to secondary leakage should be conservatively assumed to be from one steam generator) during the cycle preceding the inspection which is the subject of the report, ~~and~~

k. For Unit 2 ~~following completion of an inspection performed in Refueling Outage 15 (and any inspections performed in the subsequent operating cycle)~~, the calculated accident induced leakage rate from the portion of the tubes below ~~16.95~~ 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 ~~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.

ATTACHMENT 3
Markup of Technical Specifications Pages for Byron Station, Units 1 and 2

Byron Station, Units 1 and 2

Facility Operating License Nos. NPF-37 and NPF-66

Proposed Technical Specifications Pages for Byron Station, Units 1 and 2

5.5-8
5.5-9
5.5-10
5.6-7

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

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

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

c. Provisions for SG tube repair criteria.

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

14.01

For Unit 2 ~~during Refueling Outage 16 and the subsequent operating cycle~~, tubes with service-induced flaws located greater than ~~16.95~~ inches below the top of the tubesheet do not require plugging or repair. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to ~~16.95~~ inches below the top of the tubesheet shall be plugged or repaired upon detection.

14.01

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

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

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

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. For Unit 2 ~~during Refueling Outage 16 and the subsequent operating cycle~~, portions of the tube below ~~16.95~~ 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 ~~during Refueling Outage 16 and the subsequent operating cycle~~, if crack indications are found in any SG tube from 14.01 ~~16.95~~ inches below the top of the tubesheet on the hot leg side to 14.01 ~~16.95~~ inches below the top of the tubesheet on the cold leg side, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less).

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

5.6 Reporting Requirements

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

j. For Unit 2 ~~following completion of an inspection performed in Refueling Outage 16 (and any inspections performed in the subsequent operating cycle)~~, the operational primary to secondary leakage rate observed (greater than three gallons per day) in each steam generator (if it is not practical to assign the leakage to an individual steam generator, the entire primary to secondary leakage should be conservatively assumed to be from one steam generator) during the cycle preceding the inspection which is the subject of the report, ~~and~~

k. For Unit 2 ~~following completion of an inspection performed in Refueling Outage 16 (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 14.01

l. For Unit 2 ~~following completion of an inspection performed in Refueling Outage 16 (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.

ATTACHMENT 4
Markup of Technical Specifications Bases Page for Braidwood Station, Units 1 and 2

Braidwood Station, Units 1 and 2

Facility Operating License Nos. NPF-72 and NPF-77

Proposed Technical Specifications Bases Page for Braidwood Station, Units 1 and 2

B 3.4.19-3

BASES

LCO

The LCO requires that SG tube integrity be maintained. The LCO also requires that all SG tubes that satisfy the repair criteria be plugged or repaired in accordance with the Steam Generator Program.

During an SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is repaired or removed from service by plugging. If a tube was determined to satisfy the repair criteria but was not plugged or repaired, the tube may still have tube integrity.

In the context of this Specification, a SG tube is defined as the entire length of the tube, including the tube wall and any repairs made to it, between the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at the tube outlet. For Unit 2 ~~during Refueling Outage 15 and the subsequent operating cycle~~, the portion of the tube below 14.01 ~~16.95~~ inches from the top of the tubesheet is excluded. The tube-to-tubesheet weld is not considered part of the tube.

A SG tube has tube integrity when it satisfies the SG performance criteria. The SG performance criteria are defined in Specification 5.5.9, "Steam Generator Program," and describe acceptable SG tube performance. The Steam Generator Program also provides the evaluation process for determining conformance with the SG performance criteria.

There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE (i.e., primary to secondary LEAKAGE). Failure to meet any one of these criteria is considered failure to meet the LCO.

The structural integrity performance criterion provides a margin of safety against tube burst or collapse under normal and accident conditions, and ensures structural integrity of the SG tubes under all anticipated transients included in the design specification. Tube burst is defined as, "The gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation." Tube collapse is defined as, "For the load displacement curve for a given structure, collapse occurs at the top of the load versus displacement curve where the slope of the curve becomes zero." The structural integrity performance criterion provides guidance on assessing loads that have a significant effect on burst or collapse.

ATTACHMENT 5
Markup of Technical Specifications Bases Page for Byron Station, Units 1 and 2

Byron Station, Units 1 and 2

Facility Operating License Nos. NPF-37 and NPF-66

Proposed Technical Specifications Bases Page for Byron Station, Units 1 and 2

B 3.4.19-3

BASES

LCO

The LCO requires that SG tube integrity be maintained. The LCO also requires that all SG tubes that satisfy the repair criteria be plugged or repaired in accordance with the Steam Generator Program.

During an SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is repaired or removed from service by plugging. If a tube was determined to satisfy the repair criteria but was not plugged or repaired, the tube may still have tube integrity.

In the context of this Specification, a SG tube is defined as the entire length of the tube, including the tube wall and any repairs made to it, between the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at the tube outlet. For Unit 2 ~~during Refueling Outage 16 and the subsequent operating cycle~~, the portion of the tube below 14.01 ~~16.95~~ inches from the top of the tubesheet is excluded. The tube-to-tubesheet weld is not considered part of the tube.

A SG tube has tube integrity when it satisfies the SG performance criteria. The SG performance criteria are defined in Specification 5.5.9, "Steam Generator Program," and describe acceptable SG tube performance. The Steam Generator Program also provides the evaluation process for determining conformance with the SG performance criteria.

There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE (i.e., primary to secondary LEAKAGE). Failure to meet any one of these criteria is considered failure to meet the LCO.

The structural integrity performance criterion provides a margin of safety against tube burst or collapse under normal and accident conditions, and ensures structural integrity of the SG tubes under all anticipated transients included in the design specification. Tube burst is defined as, "The gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation." Tube collapse is defined as, "For the load displacement curve for a given structure, collapse occurs at the top of the load versus displacement curve where the slope of the curve becomes zero." The structural integrity performance criterion provides guidance on assessing loads that have a significant effect on burst or collapse.

ATTACHMENT 6
Summary of Regulatory Commitments

The following table identifies commitments made in this document. (Any other actions discussed in the submittal represent intended or planned actions. They are described to the NRC for the NRC's information and are not regulatory commitments.)

COMMITMENT	COMMITTED DATE OR "OUTAGE"	COMMITMENT TYPE	
		ONE-TIME ACTION (Yes/No)	PROGRAMMATIC ACTION (Yes/No)
For the condition monitoring (CM) assessment, the component of operational leakage from the prior cycle from below the H* distance will be multiplied by a factor of 3.11 and added to the total accident leakage from any other source and compared to the allowable accident induced leakage limit. For the operational assessment (OA), the difference between the allowable accident induced leakage and the accident induced leakage from sources other than the tubesheet expansion region will be divided by 3.11 and compared to the observed operational leakage. An administrative operational leakage limit will be established to not exceed the calculated value. Applicable to Braidwood Unit 2 and Byron Unit 2.	During scheduled inspection required by TS 5.5.9, "Steam Generator (SG) Program," for Braidwood Unit 2 and Byron Unit 2.	No	Yes
EGC commits to monitor for tube slippage as part of the steam generator tube inspection program. Applicable to Braidwood Unit 2 and Byron Unit 2.	During scheduled inspection required by TS 5.5.9, "Steam Generator (SG) Program," for Braidwood Unit 2 and Byron Unit 2.	No	Yes

ATTACHMENT 7

Westinghouse Affidavit and Authorization Letter

CAW-12-3369

Westinghouse

Westinghouse Electric Company
Nuclear Services
1000 Westinghouse Drive
Cranberry Township, PA 16066
USA

U.S. Nuclear Regulatory Commission
Document Control Desk
11555 Rockville Pike
Rockville, MD 20852

Direct tel: (412) 374-4643
Direct fax: (724) 720-0754
e-mail: greshaja@westinghouse.com
Proj letter: CAE-12-10/CCE-12-12

CAW-12-3369

January 19, 2012

APPLICATION FOR WITHHOLDING PROPRIETARY
INFORMATION FROM PUBLIC DISCLOSURE

Subject: WCAP-17330-P, Revision 1, "H*: Resolution of NRC Technical Issue Regarding Tubesheet Bore Eccentricity (Model F/Model D5)" (Proprietary), dated June 2011 and LTR-SGMP-11-58, "WCAP-17330-P, Revision 1 Erratum" (Proprietary), dated July 6, 2011

The proprietary information for which withholding is being requested in the above-referenced reports is further identified in Affidavit CAW-12-3369 signed by the owner of the proprietary information, Westinghouse Electric Company LLC. The affidavit, which accompanies this letter, sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of 10 CFR Section 2.390 of the Commission's regulations.

Accordingly, this letter authorizes the utilization of the accompanying affidavit by Exelon Generation Company, LLC.

Correspondence with respect to the proprietary aspects of the application for withholding or the Westinghouse affidavit should reference this letter, CAW-12-3369, and should be addressed to J. A. Gresham, Manager, Regulatory Compliance, Westinghouse Electric Company LLC, Suite 428, 1000 Westinghouse Drive, Cranberry Township, PA 16066.

Very truly yours,

J. A. Gresham, Manager
Regulatory Compliance

Enclosures

CAW-12-3369

AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA:

ss

COUNTY OF BUTLER:

Before me, the undersigned authority, personally appeared J. A. Gresham, who, being by me duly sworn according to law, deposes and says that he is authorized to execute this Affidavit on behalf of Westinghouse Electric Company LLC (Westinghouse), and that the averments of fact set forth in this Affidavit are true and correct to the best of his knowledge, information, and belief:

J. A. Gresham, Manager
Regulatory Compliance

Sworn to and subscribed before me
this 19th day of January 2012

Cynthia Olesky
Notary Public

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Cynthia Olesky, Notary Public
Manor Boro, Westmoreland County
My Commission Expires July 16, 2014
Member, Pennsylvania Association of Notaries

(1) I am Manager, Regulatory Compliance, in Nuclear Services, Westinghouse Electric Company LLC (Westinghouse), and as such, I have been specifically delegated the function of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear power plant licensing and rule making proceedings, and am authorized to apply for its withholding on behalf of Westinghouse.

(2) I am making this Affidavit in conformance with the provisions of 10 CFR Section 2.390 of the Commission's regulations and in conjunction with the Westinghouse Application for Withholding Proprietary Information from Public Disclosure accompanying this Affidavit.

(3) I have personal knowledge of the criteria and procedures utilized by Westinghouse in designating information as a trade secret, privileged or as confidential commercial or financial information.

(4) Pursuant to the provisions of paragraph (b)(4) of Section 2.390 of the Commission's regulations, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure should be withheld.

(i) The information sought to be withheld from public disclosure is owned and has been held in confidence by Westinghouse.

(ii) The information is of a type customarily held in confidence by Westinghouse and not customarily disclosed to the public. Westinghouse has a rational basis for determining the types of information customarily held in confidence by it and, in that connection, utilizes a system to determine when and whether to hold certain types of information in confidence. The application of that system and the substance of that system constitutes Westinghouse policy and provides the rational basis required.

Under that system, information is held in confidence if it falls in one or more of several types, the release of which might result in the loss of an existing or potential competitive advantage, as follows:

(a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of

Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.

(b) It consists of supporting data, including test data, relative to a process (or component, structure, tool, method, etc.), the application of which data secures a competitive economic advantage, e.g., by optimization or improved marketability.

(c) Its use by a competitor would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing a similar product.

(d) It reveals cost or price information, production capacities, budget levels, or commercial strategies of Westinghouse, its customers or suppliers.

(e) It reveals aspects of past, present, or future Westinghouse or customer funded development plans and programs of potential commercial value to Westinghouse.

(f) It contains patentable ideas, for which patent protection may be desirable.

There are sound policy reasons behind the Westinghouse system which include the following:

(a) The use of such information by Westinghouse gives Westinghouse a competitive advantage over its competitors. It is, therefore, withheld from disclosure to protect the Westinghouse competitive position.

(b) It is information that is marketable in many ways. The extent to which such information is available to competitors diminishes the Westinghouse ability to sell products and services involving the use of the information.

(c) Use by our competitor would put Westinghouse at a competitive disadvantage by reducing his expenditure of resources at our expense.

(d) Each component of proprietary information pertinent to a particular competitive advantage is potentially as valuable as the total competitive advantage. If competitors acquire components of proprietary information, any one component may be the key to the entire puzzle, thereby depriving Westinghouse of a competitive advantage.

(e) Unrestricted disclosure would jeopardize the position of prominence of Westinghouse in the world market, and thereby give a market advantage to the competition of those countries.

(f) The Westinghouse capacity to invest corporate assets in research and development depends upon the success in obtaining and maintaining a competitive advantage.

(iii) The information is being transmitted to the Commission in confidence and, under the provisions of 10 CFR Section 2.390; it is to be received in confidence by the Commission.

(iv) The information sought to be protected is not available in public sources or available information has not been previously employed in the same original manner or method to the best of our knowledge and belief.

(v) The proprietary information sought to be withheld in this submittal is that which is appropriately marked in WCAP-17330-P, Revision 1, "H*: Resolution of NRC Technical Issue Regarding Tubesheet Bore Eccentricity (Model F /Model D5)" (Proprietary), dated June 2011 and LTR-SGMP-11-58, "WCAP-17330-P, Revision 1 Erratum" (Proprietary), dated July 6, 2011, for submittal to the Commission, being transmitted by Exelon Generation Company, LLC Letter and Application for Withholding Proprietary Information from Public Disclosure, to the Document Control Desk. The proprietary information as submitted by Westinghouse for Byron Unit 2 and Braidwood Unit 2 is that associated with the technical justification of the H* Alternate Repair Criteria for hydraulically expanded steam generator tubes and may be used only for that purpose.

This information is part of that which will enable Westinghouse to:

(a) License the H* Alternate Repair Criteria.

Further this information has substantial commercial value as follows:

(a) Westinghouse plans to sell the use of the information to its customers for the purpose of licensing the H* Alternate Repair Criteria.

(b) Westinghouse can sell support and defense of the H* criteria.

(c) The information requested to be withheld reveals the distinguishing aspects of a methodology which was developed by Westinghouse.

Public disclosure of this proprietary information is likely to cause substantial harm to the competitive position of Westinghouse because it would enhance the ability of competitors to provide similar technical justification and licensing defense services for commercial power reactors without commensurate expenses. Also, public disclosure of the information would enable others to use the information to meet NRC requirements for licensing documentation without purchasing the right to use the information.

The development of the technology described in part by the information is the result of applying the results of many years of experience in an intensive Westinghouse effort and the expenditure of a considerable sum of money.

In order for competitors of Westinghouse to duplicate this information, similar technical programs would have to be performed and a significant manpower effort, having the requisite talent and experience, would have to be expended.

Further the deponent sayeth not.

PROPRIETARY INFORMATION NOTICE

Transmitted herewith are proprietary and/or non-proprietary versions of documents furnished to the NRC in connection with requests for generic and/or plant-specific review and approval.

In order to conform to the requirements of 10 CFR 2.390 of the Commission's regulations concerning the protection of proprietary information so submitted to the NRC, the information which is proprietary in the proprietary versions is contained within brackets, and where the proprietary information has been deleted in the non-proprietary versions, only the brackets remain (the information that was contained within the brackets in the proprietary versions having been deleted). The justification for claiming the information so designated as proprietary is indicated in both versions by means of lower case letters (a) through (f) located as a superscript immediately following the brackets enclosing each item of information being identified as proprietary or in the margin opposite such information. These lower case letters refer to the types of information Westinghouse customarily holds in confidence identified in Sections (4)(ii)(a) through (4)(ii)(f) of the affidavit accompanying this transmittal pursuant to 10 CFR 2.390(b)(1).