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Exelon Nuclear

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10 CFR 50.90

U. S. Nuclear Regulatory Commission
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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) 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) is requesting 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 permanently revise Technical Specifications (TS) 5.5.9, "Steam Generator (SG) Program," to exclude portions of the tube below the top of the steam generator tubesheet from periodic steam generator tube inspections and plugging or repair. In addition, reporting requirement changes are proposed to TS 5.6.9, "Steam Generator (SG) Tube Inspection Report." This permanent change is supported by Westinghouse Electric Company, LLC, (Westinghouse) WCAP-17072-P, Revision 0, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model D5)."

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

The attached request is subdivided as shown below.

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.

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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 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 authorization letter CAW-09-2584 with accompanying affidavit, Proprietary Information Notice, and Copyright Notice for withholding the proprietary information provided in Attachment 8.

Attachment 8 provides Westinghouse WCAP-17072-P, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model D5)," dated May 2009 (Proprietary).

Attachment 9 provides Westinghouse WCAP-17072-NP, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model D5)," dated May 2009 (Non-Proprietary).

Attachment 10 provides Westinghouse letter LTR-SGMP-09-79, "WCAP-17072 Errata and Clarifications," dated June 2, 2009.

As Attachment 8 contains information proprietary to Westinghouse, it is supported by an affidavit signed by Westinghouse, the owner of the information (Attachment 7). 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 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 listed above or the supporting Westinghouse affidavit should reference CAW-09-2584 and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company, LLC, P.O. Box 355, Pittsburgh, Pennsylvania, 15230-0355.

The proposed change has 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 amendments by October 1, 2009, to support implementation during the Braidwood Unit 2 fall 2009 and Byron Unit 2 spring 2010 refueling outages. Once approved, the amendment will be implemented within 30 days for Braidwood Unit 2 and within 60 days for Byron Unit 2.

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 non-proprietary attachments to the designated State Official.

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

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 24th day of June 2009.

Respectfully,

Patrick R. Simpson
Manager – Licensing
Exelon Generation Company, LLC

Attachments:

1. Evaluation of Proposed Changes
2. Proposed Technical Specifications Pages for Braidwood Station, Units 1 and 2
3. Proposed Technical Specifications Pages for Byron Station, Units 1 and 2
4. Proposed Technical Specifications Bases Page for Braidwood Station, Units 1 and 2
5. Proposed Technical Specifications Bases Page for Byron Station, Units 1 and 2
6. Summary of Regulatory Commitments
7. Westinghouse Affidavit and Authorization Letter CAW-09-2584
8. Westinghouse WCAP-17072-P, Revision 0 (Proprietary)
9. Westinghouse WCAP-17072-NP, Revision 0 (Non-Proprietary)
10. Westinghouse WCAP-17072 Errata and Clarifications

cc:

NRC Regional Administrator, Region III
NRC Senior Resident Inspector, Braidwood Station
NRC Senior Resident Inspector, Byron Station

ATTACHMENT 1

Evaluation of Proposed Changes

1.0 SUMMARY DESCRIPTION

2.0 DETAILED DESCRIPTION

3.0 TECHNICAL EVALUATION

4.0 REGULATORY EVALUATION

- 4.1 Applicable Regulatory Requirements/Criteria
- 4.2 Precedent
- 4.3 No Significant Hazards Consideration
- 4.4 Conclusions

5.0 ENVIRONMENTAL CONSIDERATION

6.0 REFERENCES

1.0 SUMMARY DESCRIPTION

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 permanently revise Technical Specifications (TS) 5.5.9, "Steam Generator (SG) Program," to exclude portions of the tube below the top of the steam generator (SG) tubesheet from periodic SG tube inspections and plugging or repair. The proposed amendment also revises the wording of reporting requirements provided in the Braidwood Station and Byron Station TS 5.6.9, "Steam Generator (SG) Tube Inspection Report."

This permanent change is supported by 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 (Reference 1), as clarified by Westinghouse errata letter (Reference 9). WCAP-17072-P recommends an H* value of 13.8 inches based on the statistical confidence limits of 95/50; however, EGC has chosen to use an H* value of 16.95 inches for additional conservatism. This more conservative value was discussed between the NRC and industry representatives, including EGC, on May 27, 2009.

Approval of this amendment application is requested by October 1, 2009, to support SG inspection activities during the Braidwood Unit 2 refueling outage 14 (fall 2009), the Byron Unit 2 refueling outage 15 (spring 2010), and their respective subsequent operating cycles.

2.0 DETAILED DESCRIPTION

<u>Proposed changes to current Technical Specifications:</u>

The current TS identified in this section are based on the Byron Station TS. Any differences between the current Braidwood and Byron TS are identified in braces with the specific Braidwood wording identified in brackets (e.g., "...during {Refueling Outage 14 [Braidwood: Refueling Outage 13]}").

The proposed final wording of the Braidwood and Byron TS are identical.

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 except if permitted to remain in service through application of the alternate repair criteria discussed in TS 5.5.9.c.4. For Unit 2 only, during {Refueling Outage 14 [Braidwood: Refueling Outage 13]} and the subsequent operating cycle, flaws identified in the portion of the tube from the top of the tubesheet to

17 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.

4. The following tube repair criteria shall be applied as an alternate to the 40% depth-based criteria of TS 5.5.9.c.1:

   i. For Unit 2 only, during {Refueling Outage 14 [Braidwood: Refueling Outage 13]} and the subsequent operating cycle, tubes with flaws having a circumferential component less than or equal to 203 degrees found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet do not require plugging or repair. Tubes with flaws having a circumferential component greater than 203 degrees found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet shall be removed from service. Tubes with axial indications found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging or repair.

      When more than one flaw with circumferential components is found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet with the total of the circumferential components greater than 203 degrees and an axial separation distance of less than 1 inch, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to count the overlapped portions only once in the total of circumferential components. {[Braidwood: When one or more flaws with circumferential components are found in the portion of the tube within 1 inch from the bottom of the tubesheet, and the total of the circumferential components found in the tube exceeds 94 degrees, then the tube shall be removed from service.]}

      When one or more flaws with circumferential components are found in the portion of the tube within 1 inch from the bottom of the tubesheet and within 1 inch axial separation distance of a flaw above 1 inch from the bottom of the tubesheet, and the total of the circumferential components found in the tube exceeds 94 degrees, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is

acceptable to count the overlapped portions only once in the total of circumferential components.

TS 5.5.9.c would be revised as follows. Added text is bolded and italicized.

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

TS 5.5.9.d would be revised as follows. Added text is bolded and italicized.

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. ***For Unit 1, 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, 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 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, and that may satisfy the applicable tube repair criteria.***

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

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

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

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

TS 5.6.9 currently states:

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

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

a. 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 14 [Braidwood: Refueling Outage 13]} (and any inspections performed in the subsequent operating cycle), the number of indications and location, size, orientation, and whether initiated on primary or secondary side for each service induced flaw detected within the thickness of the tubesheet, and the total of the circumferential components and any circumferential overlap below 17 inches from the top of the tubesheet, as determined in accordance with TS 5.5.9 c.4.i,

k. For Unit 2, following completion of an inspection performed in {Refueling Outage 14 [Braidwood: Refueling Outage 13]} (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

l. For Unit 2, following completion of an inspection performed in {Refueling Outage 14 [Braidwood: Refueling Outage 13]} (and any inspections performed in the subsequent operating cycle), the calculated accident leakage rate from the lowermost 4-inches of tubing for the most limiting accident in the most limiting steam generator.

TS 5.6.9 would be revised as follows. Added text is bolded and italicized.

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, the operational primary to secondary leakage rate observed (greater than three gallons per day) in each steam generator (if it is not practical to assign the leakage to an individual steam generator, the entire primary to secondary leakage should be conservatively assumed to be from one steam generator) during the cycle preceding the inspection which is the subject of the report,

k. ***For Unit 2, the calculated accident induced leakage rate from the portion of the tubes below 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 2.03 times the maximum operational primary to secondary leakage rate, the report should describe how it was determined, and***

l. ***For Unit 2, the results of monitoring for tube axial displacement (slippage). If slippage is discovered, the implications of the discovery and corrective action shall be provided.***

As previously stated, the proposed final wording of the Braidwood and Byron TS are identical. The marked-up TS pages provided in Attachments 2 and 3 indicate the changes to the Braidwood and Byron Stations' TS, respectively.

3.0 TECHNICAL EVALUATION

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 2); EPRI 1013706, Pressurized Water Reactor Steam Generator Examination Guidelines (Reference 6); EPRI 1012987, Steam Generator Integrity Assessment Guidelines (Reference 7); 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," of Reference 6.

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 5) 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

2004-001, "Requirements for Steam Generator Tube Inspections," (Reference 4). Since the Braidwood Station Unit 2 and Byron Station Unit 2 contain Westinghouse Model D5 SGs that were fabricated with thermally treated Alloy 600 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 2009 refueling outage for Braidwood Station Unit 2 and the spring 2010 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 at the elevation near the hot leg tube end.

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 over expansions 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 Reference 6, and TS 5.5.9. According to Reference 6, the inspection plan is expanded, if necessary, due to confirmed degradation in the region required to be examined (i.e., a tube crack). Inspection expansion was necessary 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.

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.

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 Westinghouse Electric Company, LLC WCAP-17072-P, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model D5)" (Reference 1). 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 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. WCAP-17072-P provides technical justification for the portion of the tubesheet expansion region being inspected being 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 WCAP-17072-P. The tube-to-tubesheet radial contact pressure provides resistance to tube pull out.

Primary-to-secondary leakage from tube degradation 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 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 Reference 2 and draft NRC Regulatory Guide (RG) 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes," (Reference 3) 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 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 Table 9-7. However, EGC will use the more conservative value of 2.03 accident leak rate ratio for the most limiting SG model design identified in WCAP-17072-P Table 9-7. 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 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 bounding plant for each model of SG and to assure that the design basis accident contact pressures are greater than the normal operating pressure contact pressure are contained in Section 6 of WCAP-17072-P.

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.

However, 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 associated with the plant's no load condition. Thus, an increase in leakage would not be expected to occur as a result of the viscosity change. The increase in leakage would only be a function of the increase in primary to secondary pressure differential. The resulting leak rate ratio for the SLB and FLB events is 2.03, which is the bounding value for all SG designs evaluated in WCAP-17072-P.

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 (Table 9-7, Reference 1) 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. 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).

As described in Section 9.2.3.1 of Reference 1, the plant transient response following a full power double-ended FLB for a Model D5 SG exhibits a cooldown characteristic instead of a heat-up transient, as opposed to that generally presented in SG design transients and in the Updated Final Safety Analysis Report (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 of the reasons provided in Reference 1 Section 9.2.3.1.

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 options, the maximum temperature would be approximately the no load temperature and would be well below normal operating temperature.

Since the FLB transient temperature considered in Reference 1 would not be expected to exceed the normal operating temperature, the viscosity ratio for the FLB transient is set to 1.0.

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. However, EGC will apply a factor of 2.03 to the normal operating leakage associated with the tubesheet expansion region in the condition monitoring (CM) and operational assessment (OA). The leakage factor of 2.03 is a bounding value for all SG designs, both hot and cold legs, in Table 9-7 of WCAP-17072-P. 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 2.03 and added to the total leakage from any other source and compared to the allowable accident induced leakage limit. For the OA, the difference between the allowable leakage and the accident induced leakage from sources other than the tubesheet expansion region will be divided by 2.03 and compared to the observed operational leakage.

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 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 determined that degradation in tubing below 13.8 inches from the top of the tubesheet does not require inspection and plugging or repair. The inspection of the portion of the tubes above 13.8 inches from the top of the tubesheet for tubes that have been hydraulically expanded in the tubesheet provides a high level of confidence that the structural and leakage performance criteria are maintained during normal operating and accident conditions. Although WCAP-17072-P determined the H* inspection depth of 13.8 inches from the top of the tubesheet, EGC is conservatively adding margin to this value and an H* inspection and plugging or repair depth of 16.95 inches from the top of the tubesheet is used. The additional margin is consistent with a 95/95 whole plant value.

WCAP-17072-P, 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).

In addition, the NRC has requested that licensees determine if there are any significant deviations in the location of the bottom of the expansion transition (BET) relative to the top of tubesheet that would invalidate assumptions in WCAP-17072-P. Therefore, EGC commits to perform a one-time verification of tube expansion locations to determine if any significant deviations exist from the top of tubesheet to the BET for Braidwood Station Unit 2 and Byron Station Unit 2. If any significant deviations are found, the condition will be entered into the corrective action program and dispositioned (Reference Summary of Regulatory Commitments in Attachment 6).

4.0 REGULATORY EVALUATION

4.1 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.

In Reference 8, the NRC approved a license amendment to fully implement an Alternative Source Term (AST), pursuant to 10 CFR 50.67. 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, 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 Reference 2, provides reasonable assurance that the SG tubing remains capable of fulfilling its specific safety function of maintaining the reactor coolant pressure boundary. The Reference 2 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 TS. (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-17072-P determined that degradation in tubing below 13.8 inches from the top of the tubesheet portion of the tube does not require inspection and plugging or repair. However, EGC is conservatively adding margin to this value and an H* inspection and plugging or repair depth of 16.95 inches from the top of the tubesheet will be used and serves as the bases for the SG tube inspection program. As such, the Braidwood Station Unit 2 and Byron Station Unit 2 inspection programs provide a high level of confidence that the structural and leakage criteria are maintained during normal operating and accident conditions.

4.2 Precedents

Similar license amendment requests to revise TS for permanent alternate repair criteria were submitted as indicated below.

1) Letter from M. J. Ajluni (SNOC) to U. S. NRC, "Vogtle Electric Generating Plant License Amendment Request to Revise Technical Specification (TS) Sections 5.5.9, 'Steam Generator (SG) Program' and TS 5.6.10, 'Steam Generator Tube Inspection Report' for Permanent Alternate Repair Criteria," dated May 19, 2009

2) Letter from F. W. Madden (Luminant Generation Company LLC) to U. S. NRC, "Comanche Peak Steam Electric Station (CPSES) License Amendment Request 09-007, Model D5 Steam Generator Alternate Repair Criteria," dated June 8, 2009

4.3 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 proposes to revise TS 5.6.9, "Steam Generator Tube Inspection Report," to provide reporting requirements specific to the permanent alternate repair criteria.

The proposed change defines 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-17072-P, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model D5)," 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 2, "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. However, EGC Braidwood Station Unit 2 and Byron Station Unit 2 will apply a factor of 2.03 to the normal operating leakage associated with the tubesheet expansion region in the condition monitoring (CM) and operational assessment (OA). The leakage factor of 2.03 is a bounding value for all SG model designs, both hot and cold legs, in Table 9-7 of WCAP-17072-P. 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 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 Table 9-7. However, EGC will use the more conservative value of 2.03 accident leak rate ratio for the most limiting SG model design identified in WCAP-17072-P Table 9-7. 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 2.03 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 2.03 and compared to the observed operational leakage.

Based on the above, the performance criteria of NEI-97-06, Revision 2, 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 identifies the specific inspection depth below which any type tube degradation has no impact on the performance criteria in NEI 97-06, Revision 2, "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 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 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.

4.4 Conclusions

In 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. WCAP-17072-P determined that the degradation in tubing below the safety significant portion of the tube does not require inspection, plugging, or repair. WCAP-17072-P serves 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.

5.0 ENVIRONMENTAL CONSIDERATION

EGC has evaluated the proposed amendment for environmental considerations. The review has determined 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.

6.0 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) NEI 97-06, Revision 2, "Steam Generator Program Guidelines," May 2005

3) Draft Regulatory Guide 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes," dated August 1976

4) NRC Generic Letter 2004-01, "Requirements for Steam Generator Tube Inspections"

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

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

7) EPRI 1012987, "Steam Generator Integrity Assessment Guidelines," Revision 2, July 2006

8) Letter from Robert F. Kuntz (NRC) to Christopher M. Crane (Exelon Generation Company, LLC), "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

9) Westinghouse letter LTR-SGMP-09-79, "WCAP-17072 Errata and Clarifications," dated June 2, 2009

ATTACHMENT 2

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

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

5.5-8
5.5-9
5.5-10
5.5-11
5.6-6
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, ~~except if permitted to remain in service through application of the alternate repair criteria discussed in TS 5.5.9.c.4. For Unit 2 only, during Refueling Outage 13 and the subsequent operating cycle, flaws identified in the portion of the tube from the top of the tubesheet to 17 inches below the top of the tubesheet shall be plugged or repaired upon detection.~~

INSERT 1

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.

~~4. The following tube repair criteria shall be applied as an alternate to the 40% depth-based criteria of Technical Specification 5.5.9.c.1:~~

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

i. For Unit 2 only, during Refueling Outage 13 and the subsequent operating cycle, tubes with flaws having a circumferential component less than or equal to 203 degrees found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet do not require plugging or repair. Tubes with flaws having a circumferential component greater than 203 degrees found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet shall be removed from service. Tubes with axial indications found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging or repair.

When more than one flaw with circumferential components is found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet with the total of the circumferential components greater than 203 degrees and an axial separation distance of less than 1 inch, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to count the overlapped portions only once in the total of circumferential components. When one or more flaws with circumferential components are found in the portion of the tube within 1 inch from the bottom of the tubesheet, and the total of the circumferential components found in the tube exceeds 94 degrees, then the tube shall be removed from service.

When one or more flaws with circumferential components are found in the portion of the tube within 1 inch from the bottom of the tubesheet and within 1 inch axial separation distance of a flaw above 1 inch from the bottom of the tubesheet, and the total of the circumferential components found in the tube exceeds 94 degrees, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to count the overlapped portions only once in the total of circumferential components.

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

For Unit 1, the

INSERT 2

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. ~~The~~ number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

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

2. Inspect 100% of the Unit 1 tubes at sequential periods of 144, 108, 72, and, thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No SG shall operate for more than 72 effective full power months or three refueling outages (whichever is less) without being inspected.

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

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

For Unit 1, if

INSERT 3

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

e. Provisions for monitoring operational primary to secondary LEAKAGE.

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

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

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

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

5.6 Reporting Requirements

5.6.8 Tendon Surveillance Report

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

5.6.9 Steam Generator (SG) Tube Inspection Report

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

a. The scope of inspections performed on each SG,

b. Active degradation mechanisms found,

c. Nondestructive examination techniques utilized for each degradation mechanism,

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

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

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

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

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

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 13 (and any inspections performed in the subsequent operating cycle), the number of indications and location, size, orientation, and whether initiated on primary or secondary side for each service induced flaw detected within the thickness of the tubesheet, and the total of the circumferential components and any circumferential overlap below 17 inches from the top of the tubesheet, as determined in accordance with TS 5.5.9 c.4.i,~~

5.6 Reporting Requirements

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

j → k.

For Unit 2, ~~following completion of an inspection performed in Refueling Outage 13 (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~~

INSERT 4 →

~~1. For Unit 2, following completion of an inspection performed in Refueling Outage 13 (and any inspections performed in the subsequent operating cycle), the calculated accident leakage rate from the lowermost 4-inches of tubing for the most limiting accident in the most limiting steam generator.~~

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

INSERT 1

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

For Unit 2 only, 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.

INSERT 2

For Unit 2, 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 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, and that may satisfy the applicable tube repair criteria.

{The text following Insert 2 will start a new paragraph.}

INSERT 3

For Unit 2, 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).

{The text following Insert 3 will start a new paragraph.}

INSERT 4

k. For Unit 2, 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 2.03 times the maximum operational primary to secondary leakage rate, the report should describe how it was determined, and

l. For Unit 2, the results of monitoring for tube axial displacement (slippage). If slippage is discovered, the implications of the discovery and corrective action shall be provided.

ATTACHMENT 3

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

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

5.5-8
5.5-9
5.5-10
5.5-11
5.6-6
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. ~~except if permitted to remain in service through application of the alternate repair criteria discussed in TS 5.5.9.c.4. For Unit 2 only, during Refueling Outage 14 and the subsequent operating cycle, flaws identified in the portion of the tube from the top of the tubesheet to 17 inches below the top of the tubesheet shall be plugged or repaired upon detection.~~

INSERT 1

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.

~~4. The following tube repair criteria shall be applied as an alternate to the 40% depth-based criteria of Technical Specification 5.5.9.c.1:~~

~~i. For Unit 2 only, during Refueling Outage 14 and the subsequent operating cycle, tubes with flaws having a circumferential component less than or equal to 203 degrees found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of~~

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

the tubesheet do not require plugging or repair. Tubes with flaws having a circumferential component greater than 203 degrees found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet shall be removed from service. Tubes with axial indications found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging or repair.

When more than one flaw with circumferential components is found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet with the total of the circumferential components greater than 203 degrees and an axial separation distance of less than 1 inch, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to count the overlapped portions only once in the total of circumferential components.

When one or more flaws with circumferential components are found in the portion of the tube within 1 inch from the bottom of the tubesheet or within 1 inch axial separation distance of a flaw above 1 inch from the bottom of the tubesheet, and the total of the circumferential components found in the tube exceeds 94 degrees, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to count the overlapped portions only once in the total of circumferential components.

For Unit 1, the

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-

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

INSERT 2

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

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

2. Inspect 100% of the Unit 1 tubes at sequential periods of 144, 108, 72, and, thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No SG shall operate for more than 72 effective full power months or three refueling outages (whichever is less) without being inspected.

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

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

For Unit 1, if

INSERT 3

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

e. Provisions for monitoring operational primary to secondary LEAKAGE.

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

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

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

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

5.6 Reporting Requirements

5.6.8 Tendon Surveillance Report

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

5.6.9 Steam Generator (SG) Tube Inspection Report

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

a. The scope of inspections performed on each SG,

b. Active degradation mechanisms found,

c. Nondestructive examination techniques utilized for each degradation mechanism,

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

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

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

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

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

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

~~j. For Unit 2, following completion of an inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle), the number of indications and location, size, orientation, and whether initiated on primary or secondary side for each service-induced flaw detected within the thickness of the tubesheet, and the total of the circumferential components and any circumferential overlap below 17 inches from the top of the tubesheet, as determined in accordance with TS 5.5.9 c.4.i,~~

5.6 Reporting Requirements

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

j → K.

For Unit 2, ~~following completion of an inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle),~~ the operational primary to secondary leakage rate observed (greater than three gallons per day) in each steam generator (if it is not practical to assign the leakage to an individual steam generator, the entire primary to secondary leakage should be conservatively assumed to be from one steam generator) during the cycle preceding the inspection which is the subject of the report, ~~and~~

INSERT 4 →

~~1. For Unit 2, following completion of an inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle), the calculated accident leakage rate from the lowermost 4-inches of tubing for the most limiting accident in the most limiting steam generator.~~

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

INSERT 1

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

For Unit 2 only, 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.

INSERT 2

For Unit 2, 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 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, and that may satisfy the applicable tube repair criteria.

{The text following Insert 2 will start a new paragraph.}

INSERT 3

For Unit 2, 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).

{The text following Insert 3 will start a new paragraph.}

INSERT 4

k. For Unit 2, 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 2.03 times the maximum operational primary to secondary leakage rate, the report should describe how it was determined, and

l. For Unit 2, the results of monitoring for tube axial displacement (slippage). If slippage is discovered, the implications of the discovery and corrective action shall be provided.

ATTACHMENT 4

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

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 12 and the subsequent operating cycle~~, the portion of the tube below 17 inches from the top of the ~~hot leg~~ tubesheet is excluded. The tube-to-tubesheet weld is not considered part of the tube.

16.95

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

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

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 13 and the subsequent operating cycle~~, the portion of the tube below 16.95 17 inches from the top of the ~~hot leg~~ 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)
EGC commits to monitor for tube slippage as part of the steam generator tube inspection program. Applicable to Braidwood Station Unit 2 and Byron Station Unit 2.	Required to be completed during each Braidwood Station Unit 2 and Byron Station Unit 2 steam generator eddy current inspections starting in A2R14 for Braidwood Station and B2R15 for Byron Station.	No	Yes
EGC commits to perform a one-time verification of the tube expansion to locate any significant deviations from the top of the tubesheet to the bottom of the expansion transition (BET). If any significant deviations are found, the condition will be entered into the corrective action program and dispositioned. Applicable to Braidwood Station Unit 2 and Byron Station Unit 2.	Required to be completed prior to entering Mode 4 following a steam generator tube inspection performed during the Braidwood Unit 2 A2R14 refueling outage and the Byron Station Unit 2 B2R15 refueling outage.	Yes	No

ATTACHMENT 7

Westinghouse Affidavit and Authorization Letter

CAW-09-2584

Westinghouse

Westinghouse Electric Company
Nuclear Services
P.O. Box 355
Pittsburgh, Pennsylvania 15230-0355
USA

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555-0001

Direct tel: (412) 374-4643
Direct fax: (412) 374-4011
e-mail: greshaja@westinghouse.com

Our ref: CAW-09-2584

May 21, 2009

APPLICATION FOR WITHHOLDING PROPRIETARY
INFORMATION FROM PUBLIC DISCLOSURE

Subject: WCAP-17072-P, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model D5)," dated May 2009 (Proprietary)

The proprietary information for which withholding is being requested in the above-referenced report is further identified in Affidavit CAW-09-2584 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 Nuclear.

Correspondence with respect to the proprietary aspects of the application for withholding or the Westinghouse affidavit should reference this letter, CAW-09-2584, and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P.O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

Very truly yours,

J.A. Gresham, Manager
Regulatory Compliance and Plant Licensing

Enclosures

cc: G. Bacuta (NRC OWFN 12E-1)

bcc: J. A. Gresham (ECE 4-7A) 1L
R. Bastien, 1L (Nivelles, Belgium)
C. Brinkman, 1L (Westinghouse Electric Co., 12300 Twinbrook Parkway, Suite 330, Rockville, MD 20852)
RCPL Administrative Aide (ECE 4-7A) 1L (letter and affidavit only)
G. W. Whiteman, Waltz Mill
H. O. Lagally, Waltz Mill
C. D. Cassino, Waltz Mill
J. T. Kandra, Waltz Mill
C. Hammer, Waltz Mill
D. Alexander, ECE 561B

CAW-09-2584

AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA:

ss

COUNTY OF ALLEGHENY:

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 and Plant Licensing

Sworn to and subscribed before me
this 21st day of May, 2009

Sharon L. Markle
Notary Public

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Sharon L. Markle, Notary Public
Monroeville Boro, Allegheny County
My Commission Expires Jan. 29, 2011
Member, Pennsylvania Association of Notaries

(1) I am Manager, Regulatory Compliance and Plant Licensing, 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" 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 constitute Westinghouse policy and provide 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-17072-P, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model D5)," dated May 2009 (Proprietary), for submittal to the Commission, being transmitted by Exelon Nuclear Application for Withholding Proprietary Information from Public Disclosure to the Document Control Desk. The proprietary information as submitted for use by Westinghouse for Byron Unit 2 and Braidwood Unit 2 is expected to be applicable to other licensee submittals in support of implementing an alternate repair criterion, called H*, that does not require an eddy current inspection and plugging of the tubes below a distance of 13.8 inches from the top of the tubesheet.

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

(a) Provide documentation of the analyses, methods, and testing which support the implementation of an alternate repair criterion, designated as H*, for a portion of the tubes within the tubesheet of the Byron Unit 2 and Braidwood Unit 2 steam generators.

(b) Assist the customer in obtaining NRC approval of the Technical Specification changes associated with the alternate repair criterion.

Further this information has substantial commercial value as follows:

(a) Westinghouse plans to sell the use of similar information to its customers for the purposes of meeting NRC requirements for licensing documentation.

(b) Westinghouse can sell support and defense of the technology to its customers in the licensing process.

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 calculation, evaluation 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).

COPYRIGHT NOTICE

The reports transmitted herewith each bear a Westinghouse copyright notice. The NRC is permitted to make the number of copies of the information contained in these reports which are necessary for its internal use in connection with generic and plant-specific reviews and approvals as well as the issuance, denial, amendment, transfer, renewal, modification, suspension, revocation, or violation of a license, permit, order, or regulation subject to the requirements of 10 CFR 2.390 regarding restrictions on public disclosure to the extent such information has been identified as proprietary by Westinghouse, copyright protection notwithstanding. With respect to the non-proprietary versions of these reports, the NRC is permitted to make the number of copies beyond those necessary for its internal use which are necessary in order to have one copy available for public viewing in the appropriate docket files in the public document room in Washington, DC and in local public document rooms as may be required by NRC regulations if the number of copies submitted is insufficient for this purpose. Copies made by the NRC must include the copyright notice in all instances and the proprietary notice if the original was identified as proprietary.

Exelon Nuclear

Letter for Transmittal to the NRC

The following paragraphs should be included in your letter to the NRC:

Enclosed are:

1. 1 copy of WCAP-17072-P, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model D5)," dated May 2009 (Proprietary)

2. 1 copy of WCAP-17072-NP, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model D5)," dated May 2009 (Non-Proprietary).

Also enclosed is Westinghouse authorization letter CAW-09-2584 with accompanying affidavit, Proprietary Information Notice, and Copyright Notice.

As Item 1 contains information proprietary to Westinghouse Electric Company LLC, it is 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 Commission and addresses with specificity the considerations listed in paragraph (b) (4) of Section 2.390 of the Commission's regulations.

Accordingly, it is respectfully requested that the information which is proprietary to Westinghouse be withheld from public disclosure in accordance with 10 CFR Section 2.390 of the Commission's regulations.

Correspondence with respect to the copyright or proprietary aspects of the items listed above or the supporting Westinghouse affidavit should reference CAW-09-2584 and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P.O. Box 355, Pittsburgh, Pennsylvania 15230-0355.