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U. S. Nuclear Regulatory Commission
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Braidwood Station, Unit 2
Facility Operating License No. NPF-77
NRC Docket No. STN 50-457

Subject: Response to Request for Additional Information Regarding the Braidwood Station, Unit 2, Spring 2008 Refueling Outage Steam Generator Tube Inspections

References:

1. Letter from B. Hanson (Exelon Generation Company, LLC) to U. S. NRC, "Braidwood Station, Unit 2 Thirteenth Refueling Outage Steam Generator Tube Inspection Report," dated November 11, 2008

2. Letter from M. J. David (U. S. NRC) to C. G. Pardee (Exelon Generation Company, LLC), "Braidwood Station, Unit 2 – Request for Additional Information Related to 2008 Steam Generator Tube Inservice Inspections (TAC No. ME0129)," dated April 2, 2009

In Reference 1, Exelon Generation Company, LLC (EGC), provided the results of the steam generator (SG) tube inspections performed during the Braidwood Station, Unit 2, spring 2008 refueling outage (A2R13). The NRC requested additional information to support review of the SG tube inspections in Reference 2.

The Attachment to this letter provides the requested information.

There are no regulatory commitments contained in this letter. If you have any questions concerning this letter, please contact Ms. Lisa A. Schofield at (630) 657-2815.

Respectfully,

Patrick R. Simpson

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

Attachments:

1. Response to Request for Additional Information Regarding the Braidwood Station, Unit 2, Spring 2008 Refueling Outage Steam Generator Tube Inspections

2. Westinghouse Data Management Program (ST Max) Listings and A2R13 Defined Indication and Location Codes

ATTACHMENT 1
Response to Request for Additional Information Regarding the Braidwood Station, Unit 2, Spring 2008 Refueling Outage Steam Generator Tube Inspections

In a letter dated November 11, 2008, Exelon Generation Company, LLC, (ECG) provided the results of the steam generator (SG) tube inspections performed during the Braidwood Station, Unit 2, spring 2008 refueling outage (A2R13). In order to complete its review, the NRC staff requests the following additional information.

Question 1

For each refueling outage and SG tube inspection outage since installation of the SGs, please provide the cumulative effective full power months that the SGs have operated.

Response

The following is a listing of effective full power months (EFPM) by refueling outage for Braidwood Station, Unit 2.

Braidwood Station Unit 2
Cumulative Operating Duration

Refueling Outage	Cumulative Effective Full Power Years	Cumulative Effective Full Power Months
A2R01	1.18	14.16
A2R02	2.30	27.60
A2R03	3.42	41.04
A2R04	4.58	54.96
A2R05	5.85	70.20
A2R06	7.19	86.28
A2R07	8.57	102.84
A2R08	9.97	119.64
A2R09	11.33	135.96
A2R10	12.78	153.36
A2R11	14.16	169.92
A2R12	15.60	187.20
A2R13	17.05	204.60

Question 2

Please provide the results of your foreign object search and retrieval. Also, confirm that all detected loose parts were removed from the SG. If loose parts were left in the SG, please discuss whether analyses were performed to assess whether tube integrity would be maintained with the loose parts left in the SG.

Response

A foreign object search and retrieval (FOSAR) was performed in each SG following the completion of sludge lancing. The top of the secondary tubesheet was visually inspected in the following areas: tubesheet annulus, peripheral tubes (3 - 5 tubes deep), tube lane and T-slots. Additionally, the tube lane and tube lane peripheral tubes (3 - 5 tubes deep) were inspected at the first baffle plate in each SG. A total of four objects were newly identified during the A2R13 FOSAR inspection. All four objects were successfully retrieved from the SGs, and the surrounding tubes showed no signs of tube wear based on visual and eddy current data review. Details of the four objects identified and successfully retrieved during A2R13 are provided in the table below.

Foreign Objects Identified and Removed During
Braidwood Station Unit 2 Refueling Outage A2R13

SG	Elevation	Location	Description	Comment
2A	FDB Hot-Leg	Row – 2 Col – 93	Wire 0.50" long x 0.010" dia.	Retrieved
2B	TTS Cold-Leg	Row – 47 Col – 55	Wire 0.20" long x 0.010" dia.	Retrieved
2C	TTS Hot-Leg	Row – 43 Col – 27	Wire 1.0" long x 0.010" dia.	Retrieved
2D	TTS Hot-Leg	Row – 48 Col – 75	Small Wire Clip 0.25" long x 0.20" high x 0.010" wide	Retrieved

TTS = Top of Tubesheet
FDB = Flow Distribution Baffle (First Support Plate)

As shown above, during the A2R13 inspection activities there were no newly identified secondary side foreign objects that could not be retrieved. Therefore, no engineering analysis was required for objects that could not be retrieved during A2R13.

The engineering evaluations performed in previous outages for objects that could not be removed from the secondary side of the SGs remains valid based on the following. Engineering analysis concluded that the objects would not cause significant tube wear between scheduled SG inspections. The analysis remains valid based on the fact that the 100% bobbin eddy current inspection in all four SGs during A2R13 did not identify any new secondary side foreign object wear associated with previously dispositioned objects. In addition, the Independent Qualified Data Analyst (IQDA) performed eddy current data review of the outer two tubes of the tube bundle periphery to ensure no unidentified foreign object wear was occurring. No damage was identified during this review.

Question 3

You state in Section 4.2.1 that 15 tubes in SG 2A were plugged, prior to bobbin eddy current testing being performed on the cold-leg straight section of these tubes. Please discuss how you assessed the integrity of these 15 tubes.

Response

As discussed in Reference 1, Section 4.2.1, 15 tubes in SG 2A were plugged prior to completion of bobbin eddy current testing on the cold-leg straight section of the tubes. All 15 tubes were in Row 1 (tightest radius U-Bend) in the 2A SG. This was an inadvertent act that occurred due to the inability to inspect the low row tubing (Rows 1 through 4) full-length using the bobbin probe from the hot-leg channel head. After completion of the hot-leg straight section bobbin eddy current and hot-leg tubesheet +Point™ eddy current inspection, it was identified that 15 tubes required plugging due to indications in the lower hot-leg tubesheet region. Since only one inspection robot was being used per SG, the hot-leg plugs were installed prior to removing the robot from the hot-leg channel head. In order to save dose associated with equipment change out, standard practice had been to move the robot to the cold-leg channel head and complete tube plugging, then complete any remaining cold-leg inspections. As discussed above, since these tubes were in the low row region, cold-leg eddy current inspections had not been completed prior to cold-leg plug installation. This issue was entered into both Exelon's and Westinghouse's corrective action programs. Procedural changes and computer software changes have been put in place to prevent a similar issue from occurring in the future.

The EPRI PWR Steam Generator Program Guidelines, Revision 6, do not require 100% inspection of all tube regions unless an active damage mechanism has been identified for a particular region. The cold-leg tubing in the Braidwood Unit 2 SGs does not have any damage mechanisms classified as active. Therefore, only sampling of this region on a period basis is required. During A2R13 there were a total of 4,504 tubes in service in the 2A SG. Of these 4,504 tubes, all but 15 received cold-leg bobbin eddy current inspection. This represents an approximate 99.7% sample of the cold-leg tubing during A2R13. Braidwood Station Unit 2 is currently in their 90 Effective Full Power Months (EFPM) inspection period as described in the EPRI Guidelines. As such, 100% of the tubes are required to be inspected once over the 90 EFPM period, with 50% inspected by the mid-point and the remaining 50% inspected by the end-point of the period. The 90 EFPM period started just prior to the spring 2002 outage and will end with the next scheduled outage A2R14, scheduled for October 2009. Review of previous outage data shows that each of these tubes were inspected with bobbin eddy current during each of the four previous outages (A2R09, A2R10, A2R11, A2R12). This far exceeds the EPRI Guidelines requirements for regions of tubes that do not contain active damage mechanisms.

While the cold-leg straight sections of these 15 tubes were not inspected during A2R13, as found structural integrity of these tubes is assured based on the following:

- The 15 tubes affected had been inspected through the cold-leg straight section with bobbin eddy current during each of the last four outages. No indications of degradation were identified.

- Since Braidwood Unit 2 contains thermally treated Alloy 600 tubing, and the area which was not inspected is on the cold-leg side of the tube bundle, the most likely potential damage mechanism for the 15 tubes is secondary side foreign object wear. During A2R13 secondary side visual inspection was performed down the entire tube lane region (3 - 5 tubes deep), at both the top of tubesheet and the first baffle plate in the 2A SG. No secondary side foreign objects were identified on the cold-leg side. Therefore, reasonable assurance is provided that no secondary side foreign object wear was present in the region of tubing that was not inspected during A2R13.

- None of the 15 tubes were in the population of tubes identified as potentially containing higher residual stress; refer to Reference 1, Section 5.2.1. This fact, coupled with the region of non-inspected tubing operating at cold-leg tube temperatures, provides reasonable assurance that Outside Diameter Stress Corrosion Cracking (ODSCC) at the tube support plate intersections was not present in these tubes.

Question 4

Regarding information provided in Attachments B.1 through B.9:

a. Please define the acronyms used in these attachments.

b. Please clarify the "CEG" column in Table B.8. This column appears to be related to the circumferential extent of the indications; however, it is listed for both axially and circumferentially-oriented flaws. The reason for a "large" circumferential component for an axial indication is not clear.

Response

Attachment 2 to this document provides the following Westinghouse Data Management Program (ST Max) listings to help aid in interpretation of the Westinghouse eddy current results provided in Reference 1.

- ST Max Database Fields
- All Defined Indication Codes A2R13
- All Defined Location Codes A2R13

Regarding the "CEG" column in Attachment B.8 of Reference 1, the field as defined in Attachment 2 to this document refers to Circumferential Crack Degrees (CEG). While this field provides accurate readings when referring to the circumferential indications such as Single Circumferential Indication (SCI), Multiple Circumferential Indications (MCI), Single Circumferential Signal (SCS), Multiple Circumferential Signals (MCS), it does not provide a meaningful number when associated with axial indications such as Single Axial Indication (SAI), Multiple Axial Indications (MAI), Single Axial Signal (SAS), and Multiple Axial Signals (MAS). This is due to the +Point™ probe coil design in relation to axial indications. As the axial sensitive coil approaches an axial indication the lead-in and lead-out characteristics of the coil result in an ambiguous reading related to circumferential width of axial indications. This fact has been demonstrated when using a +Point™ probe on a calibration standard that has axial indications. It is important to note that none of the axial indications reported during the Braidwood Unit 2 A2R13 outage showed a response on the circumferential sensitive coils of the +Point™ probe. Therefore, it is concluded that the axial indications did not demonstrate an actual circumferential extent.

Question 5

Please clarify the discussion in Section 6.4 as it relates to your condition monitoring assessment for tubesheet indications. The NRC staff recognizes that it approved a method for addressing tubesheet indications in A2R13 that was different than what was approved for use in the prior outage (A2R12). A different method was necessary in A2R13 given the technical questions raised by the NRC staff with the prior approach. As a result, please discuss whether the tubes with indications in the lower 4 inches of tubing (i.e., below 17-inches from the top of the tubesheet) had adequate integrity.

Response

During A2R13 all indications identified within the tubesheet region were contained within the bottom one inch of the hot-leg tubesheet. The basis of the Interim Alternate Repair Criteria (IARC) analysis is that axial indications within this region are acceptable for continued operation since they are contained within the tubesheet and have no safety significance. The largest circumferential indication identified in this region during A2R13 had an arc length of 211 degrees. This tube had adequate structural integrity based on the following:

- The structural limit for a circumferential indication at the top of tubesheet region is 270 degrees. This value conservatively assumes the flaw is through-wall for the entire reported length.
- The IARC acceptance criterion for circumferential indications below 17 inches from the top of tubesheet and above one inch from the bottom of the tubesheet is 203 degrees. This value was determined with the conservative assumption that there is no contact pressure between the tube and tubesheet. This acceptance criterion was adjusted by 31 degrees to account for growth during the subsequent cycle; therefore, the as found structural limit for indications within this range is 234 degrees.
- The 211-degree circumferential indication identified at Braidwood during A2R13 met both structural limits as identified above.

During development of the IARC, concerns were raised regarding establishment of contact pressure / friction forces between the tube and the tubesheet. In order to temporarily resolve the issue prior to the Braidwood Unit 2 A2R13 outage, the IARC was developed assuming zero contact pressure / friction forces between the tube and the tubesheet. As such no credit was given to the approximately 21 inches of tubesheet expansion above the tube end weld to resist tube pull out during accident conditions. Additionally, there was uncertainty regarding the eddy current technique's capability to distinguish between cracking in the tube material as compared to cracking within the bottom tube end weld. As described in the response to question 11 contained in Attachment 4 of Reference 2,

> An industry Peer Review was conducted on March 12, 2008, at the Westinghouse Waltz Mill Site with the purpose of reviewing the Fall 2007 Catawba Unit 2 cold-leg tube indications to establish whether the reported indications are in the tube material or weld material. A consensus was reached that the 2007 Catawba Unit 2 cold-leg indications most likely existed in the tube material. However, some of the indications extend close enough to the tube end that the possibility that the flaws do extend into the weld could not be ruled out. Therefore, in order to address the potential for cracking in the tube weld in parallel to crack-like indications in the tube, the more limiting size of [Westinghouse Proprietary Number] (including the adjustment for growth) for the weld is used to establish the allowable crack size in the tube for cracks less than 1.0 inch from the tube end.

Based on no credit being taken for contact pressure and no friction forces between the tube and the tubesheet, and the uncertainty of the eddy current inspection capability to distinguish between circumferential cracks in the tube material as compared to the tube end weld, a conservative IARC repair criteria of 94 degrees for circumferential indications within 1 inch from the tube end was established for the IARC approved for A2R13. Since development of the IARC analysis, additional testing has been completed that demonstrates contact pressure / friction forces do exist between the tube and the tubesheet in hydraulically expanded tubes. A report was submitted to the NRC staff through the Nuclear Energy Institute (NEI) that supports this conclusion. (Reference 3)

When taking credit for contact pressure and friction forces existing between the tube and the tubesheet, a conservative structural limit for circumferential indications of 270 degrees is used to determine structural integrity. This is the same value used for assessing top of tubesheet circumferential indications that assumes the flaw is 100% through-wall for the entire reported length. Using this value for indications deep within the tubesheet is conservative since contact pressure / friction forces have been shown to exist, and there are no bending loads applied to indications deep within the tubesheet.

Based on the above information, the largest circumferential indication identified during the Braidwood Unit 2 A2R13 outage of 211 degrees is demonstrated to have adequate structural integrity even when the flaw is conservatively assumed to be 100% through-wall depth over the entire circumferential extent.

Question 6

In Section 6.5, you indicate that no primary-to-secondary leakage greater than 3 gallons per day was observed in the cycle prior to A2R13. You further indicate that no operational leakage was observed above the detection threshold. Since the first statement implies that some measurable leakage was detected, please clarify whether any primary-to-secondary leakage was observed (i.e., leakage above the detection threshold).

Response

The wording in Section 6.5 of Reference 1 was developed to address the Technical Specification 5.6.9.k requirement that states, "the operational primary to secondary leakage rate observed (greater than three gallons per day)." As stated in Reference 1, Section 6.5, "Braidwood Unit 2 did not observe any operational primary to secondary leakage greater than three gallons per day over the cycle preceding the inspection."

To provide additional clarification regarding observed operational primary-to-secondary leakage, chemistry sampling was taken of the Steam Jet Air Ejector and liquid SG blowdown sample locations. This sampling did not indicate any SG operational primary-to-secondary leakage. Therefore, it was determined that there was no primary-to-secondary SG operational leakage over the preceding cycle.

Question 7

You had planned to perform visual inspections of the preheater region in one SG, but later concluded that the inspections were not necessary (presumably based on the eddy current results and the results of prior inspections). Please discuss the results of the prior inspections in this region (including the inspection results from the waterbox cap plate region).

Response

During the Braidwood Unit 2 fall 2003 refueling outage (A2R10), FOSAR was conducted in the preheater region of all four SGs. The inspection was performed in the waterbox region and the high flow region of the preheater (second support plate on the cold-leg side) of each SG. This was the first inspection of these regions since initial plant startup at Braidwood Unit 2. Conference calls between Exelon Nuclear and NRC representatives were held during the A2R10 outage. The conference calls are summarized in Reference 4. The following is an excerpt from the NRC letter that summarizes the A2R10 preheater inspection results:

> ...the licensee performed FOSAR in all four SGs during the 2003 outage. The FOSAR was performed on top of the tubesheet and in the preheater region of the SGs. This was the first time that FOSAR was performed in the preheater region at Braidwood 2. Numerous objects were found during these inspections primarily in the preheater region. Most of these parts were retrieved and did not result in any tube wear; however, there were a few parts that could not be removed and/or resulted in tube wear. These latter parts are discussed further below.
>
> In SG A, a 1.25-inch long by 0.75-inch diameter object (best described as a bushing) was found located on preheater baffle B (i.e., the second cold-leg tube support). This part was initially identified during the secondary side visual inspection. Once visually identified, the eddy current data for the tubes surrounding the part was reviewed and with hindsight tube wear was identified in one tube and a possible loose part signal was identified in three tubes. This object could not be removed and has been in the SG

since 1991. This object resulted in tube wear, which measured 38-percent through-wall as determined from a +Point™ coil. This wear indication was present in prior cycles, but was distorted since the part was adjacent to an expanded preheater baffle plate support location. The three tubes surrounding the part (including the tube with the wear indication) were plugged and stabilized. The part was in the periphery of the tube bundle.

In SG B, weld slag measuring 1.125-inch by 1-inch by 0.35-inch was detected on the top of the cold-leg tubesheet. The weld slag was identified during the FOSAR inspection in 2002, but could not be retrieved. No tube wear was associated with this object. Four tubes surrounding this object were plugged and stabilized.

In SG B, two manufacturing fit-up bars (also referred to as backing bars) measuring 1-inch by 1-inch by 3-inches were found on top of preheater baffle B (i.e., the second cold-leg tube support). These bars are used to assist in the assembly of the SG and were installed (i.e., welded) on the bottom of the preheater baffle D (i.e., the third cold-leg tube support). These fit-up bars serve no structural or operational function. After visually identifying the presence of these fit-up bars, the licensee could ascertain from eddy current data that one of these bars has been present on the top of preheater baffle B (i.e., the second cold-leg tube support) since the spring of 1990, while the other has been present since the fall of 1994. These bars resulted in tube wear with one bar resulting in two wear scars (maximum depths of 28-percent and 21-percent through-wall) in one tube and the other bar resulting in one wear scar (maximum depth of 5-percent through-wall). One of these bars was also attributed to a volumetric indication, which was detected in a neighboring tube in 1994 (and measured 39-percent through-wall) and was subsequently plugged (but not stabilized) in 1997. With the visual identification of this part, this volumetric indication is now attributed to wear the fit-up bar.

In evaluating the potential for other fit-up bars to cause tube damage, the licensee determined that there are 22 fit-up bars per SG. Fourteen of these bars are on the bottom of the first hot and cold-leg tube support, 4 are on the bottom of the baffle plate D (i.e., the third cold-leg tube support), and 4 are on a portion of the preheater near the center of the tube bundle and above the first tube support plate (i.e., 1H and 1C). If these latter bars were to fall, they would most likely end up on the first tube support plate. The licensee either directly or indirectly verified that all of the backing bars were present in all four SGs. All of the backing bars were in place (with the exception of the two mentioned above). The licensee attributed the failure of these two backing bars to fabrication loads/weld shrinkage. The licensee indicated that the backing bars were most likely misaligned such that when the permanent wedges and stayrods were installed (which support and position the support plate) it resulted in high loads on the backing bars welds, which resulted in their failure. Visual inspection of the two backing bars indicated that the welds had sheared and there was no evidence that the failure was a result of fatigue.

The two backing bars found on top of preheater baffle B could not be removed from the SG. As a result, the licensee plugged and stabilized all of the tubes surrounding them. In addition, they plugged and stabilized the tubes surrounding the tube that was plugged in 1997 for the volumetric indication near one of these backing bars. As a precautionary measure, the licensee plugged and stabilized the tubes in SG B surrounding the two intact backing bars (i.e., those still attached to the bottom of preheater baffle plate D) just in case these backing bars became loose during operation.

In addition to the above loose parts, the licensee also detected five other loose parts that could not be removed. These parts were identified through the secondary side visual inspections (which were performed prior to collection of the eddy current data). Four of these parts were small wires located between a tube and the tube support plate. These four parts affected four tubes. Although these wires could be grabbed, they could not be removed. The fifth part was a small metal object located on the top of the tubesheet in the periphery of SG D. This part was 3/8-inch by ¼-inch by ¼-inch. The loose part has been present since the sixth refueling outage in 1997 and visually appears to be in the same location and has not changed in size. None of these five parts has caused any tube wear. The licensee performed an analysis to indicate that it was acceptable to leave these parts in service until the next tube inspection.

Two other indications attributed to tube wear associated with loose parts were left in service during the 2003 outage. One of the indications was slightly above the first tube support plate. A visual inspection in the area did not result in the identification of a loose part. This indication was sized and left in service. Similarly, at the location of the wear indication attributed to a loose part, a visual inspection did not result in the identification of a part so the indication was sized and left in service.

During the Braidwood Unit 2 spring 2005 inspection (A2R11), FOSAR was conducted in the preheater region of the 2B SG. No foreign objects that had the potential of causing significant tube wear were identified. The majority of objects identified in the 2B SG preheater region were successfully retrieved during A2R11. No new foreign object wear indications were identified during A2R11 in the preheater region of all four SGs based on 100% bobbin inspection of the region. Since secondary side visual inspection was not performed in the three remaining SGs during A2R11, +Point™ inspection of the pre-heater tube expansion transitions of tubes in the corner tube region was performed in the 2A, 2C and 2D SGs. No foreign object wear or indications of possible loose parts (PLP) were identified during the +Point™ inspection. The corner tube region is defined as an area in the preheater region on the second baffle plate that is adjacent to the flow blocking device. This region has been shown through industry experience to be an area where secondary side foreign objects may migrate and cause tube wear. The objects identified in the 2B SG region during A2R11 that could not be retrieved were small objects, which were evaluated for continued service. The analysis demonstrated that when using conservative wear rates, none of the objects had the potential of causing wear above the structural limit over approximately the next twenty years of operation. This analysis is supported by the A2R12 and A2R13 eddy current inspection results that did not identify any wear associated with objects in the preheater region.

In addition to the 2B SG preheater FOSAR performed during A2R11, visual inspection of the waterbox cap plate and waterbox rib region was conducted on all four SGs. This was in response to industry issues that had recently identified areas of inadequate fabrication repairs and extensive erosion in these regions. No anomalies, only trace amounts of erosion in the cap plate flow holes, were identified during the Braidwood Unit 2 inspection of these regions. No erosion was identified in the waterbox rib holes.

During the Braidwood Unit 2 fall 2006 outage (A2R12), FOSAR was conducted in the preheater region of the 2C SG. No foreign objects that had the potential of causing significant tube wear were identified. The majority of the objects identified in the 2C SG preheater region were successfully retrieved during A2R12. No new foreign object wear indications were identified during A2R12 in the preheater region of all four SGs based on 100% bobbin inspection of the region. Since secondary side visual inspection was not performed in the three remaining SGs during A2R12, +Point™ inspection of the pre-heater tube expansion transitions of tubes in the corner tube region was performed in the 2A, 2B and 2D SGs. No foreign object wear or indications of possible loose parts (PLP) were identified during the +Point™ inspection. The objects that were identified in the 2C SG region that could not be retrieved were small objects, which were evaluated for continued service. The analysis demonstrated that when using conservative wear rates, none of the objects had the potential of causing wear above the structural limit over approximately the next ten years of operation. This analysis is supported by the A2R13 eddy current inspection results that did not identify any wear associated with objects in the preheater region.

In addition to the 2C SG preheater FOSAR performed during A2R12, visual inspection of the waterbox cap plate and waterbox rib region was conducted in the 2C SG during A2R12. No anomalies, only trace amounts of erosion in the cap plate flow holes, same as that observed in this region during the previous outage (A2R11), were identified during A2R12. No erosion was identified in the waterbox rib holes.

The decision not to open the 2D SG preheater / waterbox region to perform FOSAR during A2R13 as originally scheduled was based on the following:

- Inspections performed subsequent to the initial preheater FOSAR inspection during A2R10 did not identify any foreign objects that had the potential of causing significant tube wear.
- No new secondary side foreign object wear indications had been identified in the preheater region during current (A2R13) or two previous (A2R11, A2R12) bobbin eddy current inspections.
- +Point™ inspection of the pre-heater tube expansion transitions of tubes in the corner tubes in all four SGs during A2R13 did not identify any signs of foreign object wear or possible loose parts (PLP) in the area.
- Inspection of the waterbox cap plate and rib region in the 2A SG during A2R11 did not identify any anomalies or any appreciable erosion.
- The estimated dose associated with performing FOSAR of a SG preheater region, including inspection of the waterbox cap plate and rib region is approximately 0.70 REM.

Inspection of the preheater region, waterbox cap plate and rib region in future outages are based on a frequency as determined by the outage specific degradation assessment.

Question 8

Inspections were performed on the secondary side of the SG (in this outage and prior outages). Please discuss whether the condition of the tube support plate holes was monitored during these inspections and the extent of any deposit buildup in these holes.

Response

Limited secondary side visual inspections of the upper bundle region in the Braidwood 2C SG during every outage since the spring 2002 outage (A2R09), due to limited access to this region. Single access openings of approximately 2.0 inch diameter are available at the eighth and eleventh (top) tube support plates. The intent of the visual inspection is to evaluate and trend upper bundle deposits in order to schedule future additional cleaning operations, prior to loss of secondary side pressure or developing secondary level oscillations. In addition to Exelon's review of the data, an independent consulting company reviews the data and helps determine the optimum time and process to perform secondary side cleaning. Levels of upper bundle deposit loading and quatrefoil flow hole blockage have shown no appreciable differences when comparing on a cycle-to-cycle basis.

Visual inspections are primarily performed on tubes adjacent to the tube lane and limited in-bundle inspections. During A2R13 the following inspections were performed:

Top Support Plate 8 Tubelane:

> The entire tubelane region of top of support plate 8 was visually inspected. The support plate was found to be free from any foreign objects and hard sludge deposits. The surface of the support plate is coated with a thin layer of soft sludge deposits, deposits ranged from approximately 0.120 to 0.300 inches in height. Flow holes and quatrefoils are clear and open; trace amounts of deposits are starting to develop around their edges. Tube support plate machining marks were not visible throughout the inspection. The cold-leg tube bundle is uniformly coated in deposits. The hot-leg tube bundle is sporadically coated in scale and soft sludge deposits. In several places bare tube surface was observed. In these areas it appeared that the scale coating had detached. Pieces of scale were observed in the tubelane and in-bundle regions. The tubelane in-bundle region could be viewed to a depth of approximately 4 to 6 tubes.

Top Support Plate 8 In-Bundle:

> Four in-bundle visual inspection passes were performed in cold and hot leg tube bundle columns 75-76 and 85-86. The entire length of each column was visually inspected. All four columns are similar in appearance. The surface of the support plate is coated with a thin layer of soft sludge, ranging from approximately 0.120 to 0.300 inches in height. Quatrefoil lobes and lands have a thin layer of deposits, but are open. Trace amounts of deposits are starting to develop around their edges. The hot-leg tube bundle deposits are noticeably more developed. Tube support plate machining marks were not visible throughout the inspection. The tube surfaces are sporadically coated with deposits. Scale shards were observed frequently throughout the inspection. Tube surfaces that

were not coated in scale were reflective and clean in appearance. No foreign objects or structural anomalies were observed.

Bottom Support Plate 9 Tubelane:

The manway side tubelane region of the bottom of support plate 9 was visually inspected. The support plate was found to be free from any foreign objects or hard sludge deposits. The surface of the support plate is coated with a thin layer of soft sludge; therefore, thickness could not be ascertained. Flow holes and quatrefoils are clear and open. Ridges of deposits are starting to develop around their edges on the hot-leg side. The hot-leg tube bundle deposits are noticeably more developed. Tube support plate machining marks were not visible throughout the inspection. The tube surfaces are sporadically coated with deposits. Tube surfaces that were not coated in scale were reflective and clean in appearance. No discernable support plate erosion was observed. The tubelane in-bundle region could be viewed to a depth of approximately 4 to 6 tubes.

Top Support Plate 9 Tubelane:

The manway side tubelane region of the top of support plate 9 was visually inspected. The support plate was found to be free from any foreign objects or hard sludge deposits. The surface of the support plate is coated with a layer of soft sludge and scale particles, ranging from approximately 0.120 to 0.300 inches in height. Trace amounts of deposits were observed in the quatrefoil lands and lobes, and edges were partially obstructed by deposits. The hot-leg tube bundle deposits are clearly more developed. Scale shards were observed frequently throughout the inspection. Tube support plate machining marks were not visible throughout the inspection. Tube surfaces that were not coated in scale were reflective and clean in appearance. The tubelane in-bundle region could be viewed to a depth of approximately 4 to 6 tubes.

Top Support Plate 10 Tubelane:

The manway side tubelane region of the top of support plate 10 was visually inspected. The support plate was found to be free from any foreign objects or hard sludge deposits. The surface of the support plate is coated with a layer of soft sludge and scale particles, ranging from approximately 0.120 to 0.350 inches in height. Trace amounts of deposits were observed in the quatrefoil lands and lobes, edges were partially obstructed by deposits. The hot-leg tube bundle deposits are clearly more developed. Tube support plate machining marks were not visible throughout the inspection. Tube surfaces that were not coated in scale were reflective and clean in appearance. No discernable support plate erosion was observed. The tubelane in-bundle region could be viewed to a depth of approximately 4 to 6 tubes.

Bottom Support Plate 11 Tubelane:

The manway side tubelane region of the bottom of support plate 11 was visually inspected. The support plate was found to be free from any foreign objects or hard sludge deposits. The surface of the support plate is coated with a thin layer of soft sludge; therefore, thickness could not be ascertained. Flow holes and quatrefoils are clear and open, and trace amounts of deposits are starting to develop around their edges. The hot-leg tube bundle deposits are noticeably more developed. Tube support plate machining marks were not visible throughout the inspection. The tube surfaces are sporadically coated with deposits. Tube surfaces that were not coated in scale were reflective and clean in appearance. No discernable support plate erosion was observed. The tubelane in-bundle region could be viewed to a depth of approximately 4 to 6 tubes.

Top Support Plate 11 Tubelane:

The entire tubelane region of top of support plate 11 was visually inspected. The support plate was found to be free from any foreign objects or hard sludge deposits. The surface of the support plate is coated with a thin layer of soft sludge deposits, deposits ranged from approximately 0.120 to 0.250 inches in height. Flow holes and quatrefoils are clear and open, and trace amounts of deposits are starting to develop around their edges. Tube support plate machining marks were not visible throughout the inspection. The cold-leg tube bundle is uniformly coated in deposits. The hot-leg tube bundle is sporadically coated in scale and soft sludge deposits. In several places bare tube surfaces was observed. In these areas it appeared that the scale coating had detached. Pieces of scale were observed in the tubelane and In-bundle regions. The tubelane in-bundle region could be viewed to a depth of approximately 4 to 6 tubes.

Top Support Plate 11 In-Bundle:

Four in-bundle visual inspection passes were performed in cold and hot-leg tube bundle columns 75-76 and 85-86. The entire length of each column was visually inspected. All four columns are similar in appearance. The surface of the support plate is coated with a thin layer of soft sludge, ranging from approximately 0.120 to 0.300 inches in height. Quatrefoil lobes and lands have a thin layer of deposits, but are open. Trace amounts of deposits are starting to develop around their edges. The hot-leg tube bundle deposits are noticeably more developed. Tube support plate machining marks were not visible throughout the inspection. The tube surfaces are sporadically coated with deposits. Scale shards were observed frequently throughout the inspection. Tube surfaces that were not coated in scale were reflective and clean in appearance. No foreign objects or structural anomalies were observed.

References:

1. Letter from B. Hanson (Exelon Generation Company, LLC) to U. S. NRC, "Braidwood Station, Unit 2 Thirteenth Refueling Outage Steam Generator Tube Inspection Report," dated November 11, 2008

2. Letter from P. R. Simpson (Exelon Generation Company, LLC) to U. S. NRC, "Application for Steam Generator Tube Interim Alternate Repair Criteria Technical Specification Amendment," dated February 25, 2008

3. Report from J. Riley (NEI) to J. Giitter (NRC), "Evaluation of the Statistical Variability in Coefficient of Thermal Expansion Properties of SA-508 Steel and Alloy 600," dated February 20, 2009

4. Letter from U. S. NRC to Mr. John L. Skolds (Exelon), "Summary of Conference Call with Exelon Nuclear Regarding the 2003 Steam Generator Inspections at Braidwood Unit 2 (TAC No. MC1367)," dated January 14, 2004

ATTACHMENT 2
Westinghouse Data Management Program (ST Max)
Listings and A2R13 Defined Indication and Location Codes

ST Max Database Fields

InspDate	Inspection Date
Row	Row ID
Col	Column ID
Volts	Voltage
Deg	Degrees
Ind	Indication Code
Per	Percent Indication
Chn	Channel
Locn	Location
Inch1	Inch1
Inch2	Inch2
I	Inner Diameter/ Outer Diameter / Unknown
CrLen	Crack Length Inches
CrWid	Crack Width Inches
Ceg	Circumferential Crack Degrees
BegT	Begin Test
EndT	End Test
PDia	Probe Diameter Inches
PType	Probe Symbolic Phrase
Cal	Data Set Number
L	Leg with Fixture

ATTACHMENT 2
Westinghouse Data Management Program (ST Max)
Listings and A2R13 Defined Indication and Location Codes

All Defined Indication Codes A2R13

Ind	Type	Description
ADS	Non-Ind. Signal	Absolute Drift Signal
BLG	Anomaly	Bulge
DDS	Non-Ind. Signal	Distorted Dent Signal
DFI	Indication	Differential Freespan Indication
DFS	Non-Ind. Signal	Differential Freespan Signal
DNG	Anomaly	Ding
DNT	Anomaly	Dent
DSI	Indication	Distorted Support Indication
DSS	Non-Ind. Signal	Distorted Support Signal
DTI	Indication	Distorted Tubesheet Indication
DTS	Non-Ind. Signal	Distorted Tubesheet Signal
INF	Indication	Indication Not Found
INR	Indication	Indication Not Reportable
MAI	Indication	Multiple Axial Indication
MAS	Anomaly	Multiple Axial Signal
MAM	Anomaly	Manufacturing Anomaly Mark
MBM	Anomaly	Manufacturing Burnish Mark
MCI	Indication	Multiple Circumferential Indication
MCS	Anomaly	Multiple Circumferential Signals
NDD	NDD	No Detectable Degradation
NDF	NDD	No Degradation Found
NQI	Indication	Non-Quantifiable Indication
NQS	Non-Ind. Signal	Non-Quantifiable Signal
PBC	Other	Previous Bobbin Call
PCT	Indication	Percent Thru-Wall Indication
PID	PID	Positive Identification
PLG	Not In Service	Plugged Tube
PLP	Anomaly	Possible Loose Parts
PVN	Anomaly	Permeability Variation
RBD	Retest	Retest Bad Data
RIC	Incomplete Test	Retest Incomplete
RID	Retest	Retest Identification
RMB	Retest	Retest With Mag Bias
RRT	Incomplete Test	Retest Restricted Tube
RWS	Retest	Retest Wear Scar
SAI	Indication	Single Axial Indication
SAS	Anomaly	Single Axial Signal
SCI	Indication	Single Circumferential Indication
SCS	Anomaly	Single Circumferential Signal
SLG	Anomaly	Sludge
SVI	Indication	Single Volumetric Indication
TBP	Other	To Be Plugged
VOL	Indication	Volumetric

ATTACHMENT 2
Westinghouse Data Management Program (ST Max)
Listings and A2R13 Defined Indication and Location Codes

All Defined Location Codes A2R13

Location	Type	Section	Description
THE	TUBE END	HOT LEG	Hot Leg Tube End
TSH	TOP OF TUBESHEET	HOT LEG	Hot Leg Top of Tubesheet
01H	TSP	HOT LEG	Hot Leg First Support
03H	TSP	HOT LEG	Hot Leg Third Support
05H	TSP	HOT LEG	Hot Leg Fifth Support
07H	TSP	HOT LEG	Hot Leg Seventh Support
08H	TSP	HOT LEG	Hot Leg Eighth Support
09H	TSP	HOT LEG	Hot Leg Ninth Support
10H	TSP	HOT LEG	Hot Leg Tenth Support
11H	TSP	HOT LEG	Hot Leg Eleventh Support
AV1	AVB	U-BEND	Anti-vibration Bar 1
AV2	AVB	U-BEND	Anti-vibration Bar 2
AV3	AVB	U-BEND	Anti-vibration Bar 3
AV4	AVB	U-BEND	Anti-vibration Bar 4
11C	TSP	COLD LEG	Cold Leg Eleventh Support
10C	TSP	COLD LEG	Cold Leg Tenth Support
09C	TSP	COLD LEG	Cold Leg Ninth Support
08C	TSP	COLD LEG	Cold Leg Eighth Support
07C	TSP	COLD LEG	Cold Leg Seventh Support
06C	TSP	COLD LEG	Cold Leg Sixth Support
05C	TSP	COLD LEG	Cold Leg Fifth Support
04C	TSP	COLD LEG	Cold Leg Forth Support
03C	TSP	COLD LEG	Cold Leg Third Support
02C	TSP	COLD LEG	Cold Leg Second Support
01C	TSP	COLD LEG	Cold Leg First Support
TSC	TOP OF TUBESHEET	COLD LEG	Cold Leg Top of Tubesheet
TEC	TUBE END	COLD LEG	Cold Leg Tube End