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U. S. Nuclear Regulatory Commission
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Byron Station, Unit 2
Facility Operating License Nos. NPF-66
NRC Docket Nos. 50-455

Subject: Response to Request for Additional Information Regarding the Byron Station, Unit 2 Fall 2005 Steam Generator Inspection

References:
(1) Letter from S. E. Kuczynski (Exelon Generation Company, LLC) to U. S. NRC, "Byron Station Unit 2 Steam Generator Inservice Inspection Summary Report," dated January 3, 2006 (ML060050336)

(2) E-mail from R. F. Kuntz (U. S. NRC) to D. J. Chrzanowski (Exelon Generation Company, LLC), "Byron Unit 2 SG Tube Inspection RAIs," dated July 6, 2006

Based on the review of the Reference 1 submittal, the NRC determined that additional information was required in order to complete their evaluation of the Byron Station Unit 2 Fall 2005 steam generator inspection report. The NRC requested a response to four questions contained in the Reference 2 correspondence. The attachment to this letter provides the Exelon Generation Company, LLC response to these NRC questions.

Should you have any questions concerning this letter, please contact W. Grundmann, Regulatory Assurance Manager, at (815) 406-2800.

Respectfully,

David M. Hoots
Site Vice President
Byron Nuclear Generating Station

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Attachment: Additional Information Regarding the Byron Station Unit 2 Fall 2005 Steam Generator Inspection

Attachment

Byron Station, Unit 2

Docket Number STN 50-455
License Number NPF-66

Additional Information Regarding the Byron Station Unit 2
Fall 2005 Steam Generator Inspection

Attachment

Additional Information Regarding the Byron Station Unit 2
Fall 2005 Steam Generator Inspection

Question 1

In the summary of the Nuclear Regulatory Commission's conference call with Byron Unit 2 (the licensee), dated December 7, 2005 (ML053410444), and the licensee letter dated December 5, 2005 (ML060050336), it was reported that SGs 2B and 2C were each found to have one tube with a bulge in or slightly above the tubesheet on the cold-leg side of the SG. The call summary indicated that both the tubes were preventively plugged and stabilized because the voltage of the bulges was considerably larger than the voltage from the hydraulic expansion. However, the licensee letter indicated that the tube in SG 2B was plugged and stabilized while the tube in SG 2C was only plugged. Please discuss whether this tube was plugged or plugged and stabilized.

Response:

Tube R25-C15 in the 2C Steam Generator (SG) contained a bulge indication 11.66 inches from the tube end and is located approximately 9.6 inches from the top of the tubesheet. This tube was preventatively plugged and not stabilized. The presence of the tubesheet effectively constrains the tube in the area of interest such that preventative stabilization was not necessary.

Question 2

Due to dent and dings being areas of increased stress, discuss the scope and results of any dent and ding exams performed during the end-of-cycle 12 SG tube inspections. Please discuss whether there were any new (service induced) dents/dings identified.

Response:

The current inspection performed at Byron Station Unit 2 during the end-of-cycle 12 refueling outage (B2R12) in the Fall of 2005 did not include sampling of hot leg dents or dings within the SGs. As determined by the Byron Station B2R12 degradation assessment performed prior to the start of the inspections, the population of dents and dings were not classified as having an "active damage mechanism" as defined in the Electric Power Research Institute Pressurized Water Steam Generator Examination Guidelines, Revision 6 (EPRI SG Guidelines), Section F, "Terminology." Therefore, sampling of dents and dings using rotating probe technology is performed at the frequency defined in the EPRI SG Guidelines.

In accordance with the EPRI SG Guidelines, Section 3.3.10, "Subsequent Examination of Alloy 800 or Alloy 600 Thermally Treated Tubing," the EPRI SG Guidelines for non-active damage mechanisms in thermally treated Alloy 600 tubing require inspection of 50% of the hot leg dents/dings to be completed by the outage nearest the inspection interval mid-point of the period and inspection of the remaining 50% of the dents/dings to be completed by the outage nearest the end of the period. Additionally, no SG shall

operate more than 48 months without being inspected or 2-cycles since Byron Station operates on 18-month fuel cycles.

The table below summarizes the rotating probe inspections of hot leg dents/dings at Byron Station Unit 2 during the current 90-month examination period. As can indicated in this table, Byron Station had performed 100% of the hot leg dents and dings that are greater than 5.0 volts by the period mid-point and is on-track to complete 150% of the hot leg dents/dings by the period end-point. This plan exceeds the EPRI Guideline requirement of performing 100% inspection by the end-point. There was no degradation found at dents/dings in any of the inspections at Byron Station Unit 2. Byron Station Unit 2 is in the second examination period which is 90 Effective Full Power Months (EFPM) in length. Additionally, there has been no degradation found in dents or dings at other plants in the industry that contain thermally treated Alloy 600 tubing.

Therefore, in accordance with the examination requirements of the EPRI Guidelines, there were no diagnostic rotating probe inspections of dents/dings during the B2R12 SG tube inspections.

**Byron Station Unit 2
90-Month Period Dent/Ding Inspection Summary**

	B2R08	B2R09	B2R10	B2R11	B2R12	B2R13 (Planned)
Period EFPM	0	16.6	33.4	51.0	68.4	85.8
Examination Period	Start of Period		Mid-Point			End of Period
Probe	Plus-Point	Plus-Point	Plus-Point	Plus-Point	Plus-Point	Plus-Point
Inspection Scope	25%	0%	75%	25%	0%	25%
Cumulative Percentage Inspected	25%	25%	100%	125%	125%	150%

Byron Station does not have a service induced denting mechanism. Traditional SG tube denting is caused by corrosion of carbon steel drill hole tube support plates that can be compounded by additives in the secondary side water (ex., phosphate and sulfate) that typically results in an acidic crevice environment. The support plate corrosion constricts the tube to the point of circumferential denting of the tube within the tube support plate. Byron Station Unit 2 does not contain carbon steel drill hole tube supports and does not operate with chemistry additives that would contribute to support plate denting. Therefore, this type of service induced denting is not applicable to Byron Station Unit 2.

Service induced denting in the freespan (i.e., dings) is typically caused by large foreign objects impacting the tube to create localized tube deformation. No foreign objects were found during B2R12 that were of a size that could create tube deformation. Review of dents/dings in freespan regions in the high flow regions that are susceptible to foreign object intrusion did not indicate a service induced dent/ding mechanism.

Attachment

Additional Information Regarding the Byron Station Unit 2
Fall 2005 Steam Generator Inspection

Question 3

In the staff's call summary, it was stated that a secondary-side visual inspection of the steam drum/moisture separator region of SG 2B was scheduled to be performed. Please provide the results of this secondary-side visual inspection.

Response:

During the Byron Station Unit 2 B2R12 refueling outage, visual inspection of the 2B SG secondary side steam drum and moisture separator region was performed. All areas that were accessible through the upper secondary manways were visually inspected down through the lower deck plate (refer to Figure 3-1). The visual inspection included inspection of the following components:

- Secondary moisture separator banks
- mid-deck plate
- Primary moisture separators
- Downcomer barrels and tangential nozzle assemblies
- Intermediate deck plate
- Auxiliary feedwater piping and supports
- Primary separator slip-fit joint in the lower deck region.

No degradation, erosion, deformation or weld cracking was observed in the components inspected other than the erosion identified in the primary separator region as described below.

During the visual inspection of the primary separator assembly region, areas were identified where the normally present magnetite layer was missing, thus providing areas for erosion to develop. The areas included portions of the tangential nozzles, portions of the inner surface of the primary moisture separator downcomer barrels, a number of primary separator swirl vanes, spacer tabs and orifice rings. Refer to Figure 3-2 for a sketch of these components. This condition existed on 12 of the 16 primary separator assemblies. The components identified with the missing magnetite layer are fabricated from carbon steel, typically American Society for Testing and Materials standard specification A-285, "Pressure Vessel Plates, Carbon Steel, Low and Intermediate-Tensile Strength," Grade C, material. The manufacturing nominal wall thickness for these components was 0.250-inch. To supplement the visual inspection observations, ultrasonic (UT) thickness measurements were taken in areas of magnetite loss with most apparent erosion.

Table 3-1 provides a summary of the UT thickness examinations performed on the most apparent eroded areas. Based upon the UT thickness examinations, the minimum material thickness loss observed and recorded was 0.183" on one swirl vane blade assembly. This represents a 27% reduction in material thickness.

Attachment

Additional Information Regarding the Byron Station Unit 2
Fall 2005 Steam Generator Inspection

Table 3-1
SG 2B Moisture Separator UT Result Summary

Component	Number Inspected	Minimum Wall Thickness Observed by UT	Percent Nominal Wall Loss
Primary Separator Orifice Ring	5	0.233"	7%
Primary Separator Swirl Van	5	0.183"	27%
Riser Barrel ID Wall	6	0.214"	14%
Downcomer Barrel OD Wall	4	0.188"	25%
Primary Separator Tangential Nozzle Vertical Wall	4	0.199"	20%
Primary Separator Tangential Nozzle Horizontal Wall	4	0.215"	14%

In a few instances, some of the welds that join the primary separator assembly sub-parts contained very localized material loss of not more than an estimated 25%. Additionally, on several primary separator barrel ID wall surfaces where magnetite was missing, a narrow localized depression (scallop) was observed to exist at the junction with the trailing edge of the swirl vane blades. The depression was too narrow to obtain a UT thickness measurement, but the worst-case location was estimated to have a 40% wall loss in a very localized area. There were no areas of through wall erosion observed in any of the components inspected.

Upon discovery of the eroded areas of the 2B SG primary separator assemblies, Westinghouse Electric Company, LLC (Westinghouse), original equipment manufacturer, performed an evaluation to assess the as-found condition and projected condition over the next period of operation. Areas evaluated included SG thermal performance, structural adequacy and loose parts assessment. It was concluded from the Westinghouse evaluation that the as-found condition and continued operation is acceptable. The evaluation is summarized below.

SG Thermal Performance:

The degradation noted in the visual inspections appears to be thinning of the wall of various components of the primary separator assembly. However, no through-wall holes were found in any of the components. In a worst case scenario that has an extremely low probability of occurrence, if the 27% wall loss (0.067") occurred in just one fuel cycle, the worst case as-found thickness of 0.183" could be reduced to 0.116" or 54% of nominal wall thickness. Although this deviates from the original thickness, it was concluded that the remaining wall thickness would still maintain the thermal and hydraulic conditions of the SG within the originally specified designed requirements.

Structural Adequacy:

The degradation identified in the steam drum region will have a negligible impact upon the structural adequacy of the components affected. Most material loss that has thus far been observed to exist is specific to localized areas that do not have significant applied loadings (i.e., tangential nozzles). The amount of observed material loss is not currently

considered to be significant with respect to major load conditions, such as loadings associated with steam line break or seismic events. Prior analysis performed for other SGs with more significant erosion indicate that large margins are typically present for erosion of this type when occurring at these specific locations. As a result of the observed levels of material loss and prior analysis performed for other SGs, including other Model D-5 SGs, it is expected that any operational or postulated faulted loads imposed upon these components considering further erosion potential for at least another cycle of operation will not adversely impact or compromise their structural integrity.

Loose Parts Assessment:

The steam drum components found to be degraded in the 2B SG, which include the tangential nozzles, downcomer barrels, moisture separator barrels and the primary separator swirl vane assemblies are non-nuclear safety class parts. The design of non-nuclear safety class equipment must resist failure that could prevent safety class equipment from performing its nuclear safety related function. In the case of the erosion of the identified components, the most significant condition from a safety perspective would be the potential for generation of a loose part and its subsequent impacting and sliding wear on the SG tubes.

A review of the material loss to-date has been made of the affected areas to assess the impact of the loss of metal on the structural integrity of the identified components. Based on the geometry of the components, no loss of structural integrity is expected due the material loss observed for an additional cycle of operation. A review of material loss to-date does not indicate the potential for generation of a fragment of sufficient size to cause tube wear should such a fragment migrate to the tube bundle. Also, if continued wall loss were to cause thinned areas to link, the fragment generated would not be expected to be of sufficient size to wear a tube to the minimum allowable wall thickness during the next cycle of operation. Additionally, in the event that a fragment were to be generated in the primary moisture separator region, the potential for it to exit the SG and enter other systems (i.e., main steam, feedwater, auxiliary feedwater systems) is negligible, base on system flow direction and the presence of the secondary moisture separator design that contains perforated plates and chevron vanes.

Question 4

The staff's call summary indicated the foreign object search and retrieval (FOSAR) was in progress for SG 2A and retrieval of the parts found in all SGs was in progress. Please discuss the results of the SG 2A FOSAR. In addition, if any loose parts were left in any of the SGs, discuss whether analyses were performed to ensure that tube integrity would be maintained until the next inspection of these tubes.

Response:

During the Byron Station Unit 2 B2R12 refueling outage, SG secondary side FOSAR was performed in each SG following sludge lancing of the secondary face of the tubesheet to identify and remove foreign objects that may be found. The post sludge

lance visual inspection of the tubesheet consisted of inspecting the tube lane, peripheral annulus, T-slot, and all tubes along the periphery of the tube bundle. The objective of the peripheral tube inspection was to inspect as far into the tube bundle as the inspection technology would allow, typically 3-4 tubes into the tube bundle.

Additionally, FOSAR was performed on the 2A pre-heater tube support plate (TSP 02C) to identify and remove any foreign object that may be found. The current pre-heater FOSAR strategy is to inspect one pre-heater each refueling outage on a rotating basis. This visual inspection consisted of a row-by-row in-bundle inspection of all accessible tubes from the end of the T-slot (row 21) through the last tube row (row 49) and tube columns 52 through 63 from the end of the T-slot to the divider plate (row 1). These areas consist of the high flow regions that are considered to be most susceptible to foreign material tube damage.

As a result of the post sludge lance visual inspections in the 2A SG, a total of 7 foreign objects were identified. The objects were identified as follows: 4 pieces of slag metal, 1 piece of slag metal or hard scale, 1 piece of gasket material and 1 metallic object. All objects were successfully retrieved with the exception of the one piece of slag metal/hard scale. This object is firmly wedged between two peripheral tubes and could not be removed. Since the piece was not removed, conclusive characterization could not be achieved. The piece visually appears to be either hard scale in the form of a sludge rock or a piece of slag. Eddy current inspection did not detect the presence of a foreign object on the affected tubes, hence it is likely that the object is not metallic but is composed of a tenacious sludge rock type material. There was no tube damage on the affected and surrounding tubes as determined by eddy current and visual inspection. This object was first identified during the prior end-of-cycle 11 refueling outage (B2R11) and has remained unchanged in the current B2R12 refueling outage. Westinghouse performed evaluations for the object in both the B2R11 and B2R12 outages and conservatively determined an operating period of 7.5 years for the object to wear a tube to its structural limit, although, no wear degradation was found in B2R11 or B2R12 that was associated with this object. The affected tubes remain in service. The next SG inspection is currently scheduled for the next refueling outage at the end of cycle 13 (B2R13).

As a result of the visual inspections of the 2A pre-heater TSP, 13 foreign objects were identified. Nine of the objects were characterized as small wires, similar to brush wires. The remaining four objects were characterized as small pieces of gasket material. There was no tube damage associated with these objects as determined by eddy current and visual inspection. All of the objects were successfully removed from the SG, with the exception of 1 small gasket piece and 2 small brush-like wires. Westinghouse performed a conservative evaluation that confirmed the acceptability of operation with these objects remaining in the SGs for at least two fuel cycles between inspections, which bounds the current one cycle inspection frequency.

Exelon Steam Generator Program procedures require that all foreign material remaining in the SGs require an analysis to be performed to validate that tube structural and leakage performance criteria would be met at the end of the next operating period when SG inspections would be performed. This analysis was performed for all foreign material remaining in each SG following the B2R12 inspection, including new and historical

foreign objects. Based on this analysis it was concluded that tube structural and leakage integrity is projected to be maintained throughout the next operating cycle when SG inspections are scheduled during the B2R13 refueling outage for all foreign material remaining in the SGs.

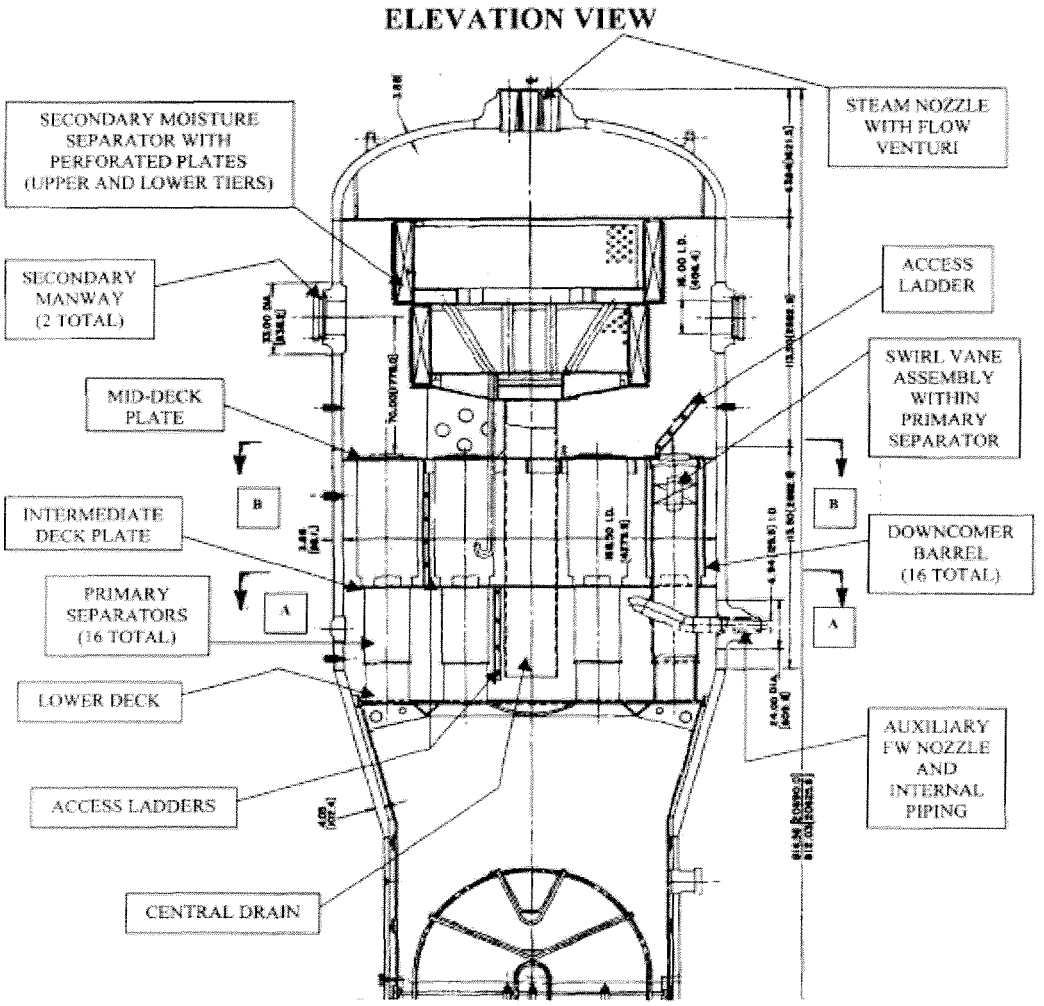

FIGURE 3-1
Westinghouse Model D-5 Generator
Byron Station Unit 2 Steam Drum Components

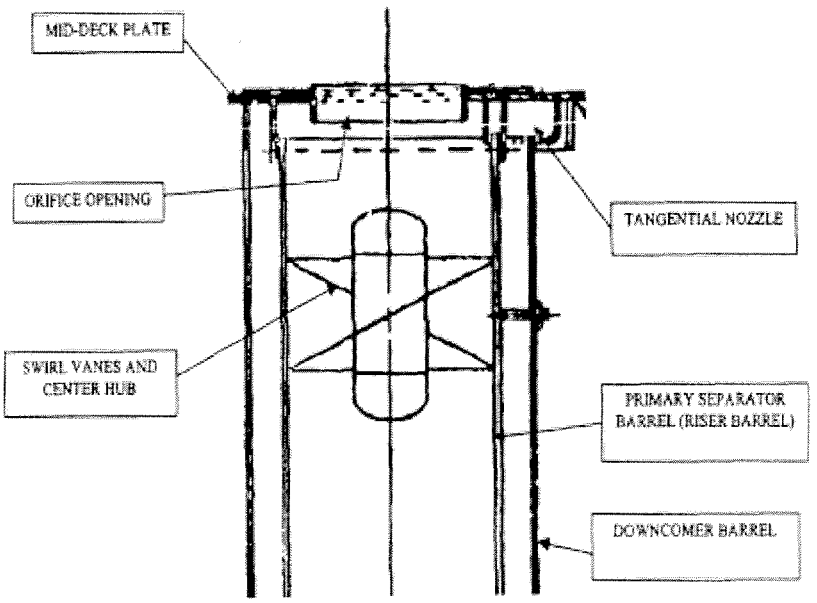

FIGURE 3-2
Westinghouse Model D-5 Generator
Byron Station Unit 2 Primary Separator Assembly