From: Peter Tam
To: Jeffrey L. Kivi
Date: 01/08/2007 4:11:29 PM
Subject: Summary of 11/27/06 Conference Call re. Prairie Island Unit 2 SG Tube Inspection **(TAC MD3441)**

Jeffrey:

On November 27, 2006, the NRC staff participated in a conference call with Prairie Island 2 representatives regarding the results of their 2006 steam generator tube inspections performed during refueling outage (RFO) 24. The topics discussed during the call are contained in an NRC letter dated November 16, 2006 (ML063120515). A summary of the information provided during the call is discussed below.

The two steam generators at Prairie Island 2 are Westinghouse model 51 steam generators. Each steam generator contains 3,388 mill annealed Alloy 600 tubes. Each tube has a nominal outside diameter of 0.875-inch and a nominal wall thickness of 0.050-inch. The tubes were roll expanded into the tubesheet at both ends for approximately 2.75-inch (i.e., they are expanded for only a fraction of the tubesheet thickness and are therefore considered partial depth hard-rolled tubes). The tubes are supported by a number of carbon steel tube support plates.

The original anti-vibration bars were removed and replaced. The tubes installed in rows 1 and 2 were subjected to an in-situ thermal stress relief in May 2000. To repair defects, many tubes have been roll expanded into the tubesheet region above the original factory roll expansions. The hot-leg temperature at Prairie Island 2 has been approximately 590-degrees Fahrenheit since commencement of initial operation. There are no sleeves installed in the Unit 2 steam generators as of 2006.

In addition to a depth-based tube repair criteria, the licensee is authorized to apply the voltage-based tube repair criteria for predominantly axially oriented outside diameter stress corrosion cracking at the tube support plate elevations. Although authorized to implement the voltage-based repair criteria, the licensee has not found it necessary to implement these criteria since no indications subject to this repair criteria have been identified at Unit 2. In addition, the licensee is authorized to leave flaws within the tubesheet region in service, provided they satisfy the F*/EF* repair criterion. The major cause of degradation within the tubesheet region is primary water stress corrosion cracking at the roll transition zones. Secondary side intergranular attack and outside diameter stress corrosion cracking have also been observed at this location.

In support of the phone call, the licensee provided the attached document that provided inspection status as of 0900 on November 26, 2006. At the time of the call, the eddy current inspections for Prairie Island 2 were nearly 100% complete. No unusual degradation or unexpected conditions were detected during the inspections. Additional clarifying information or information not included in the document provided by the licensee is summarized below:

On slide 3, the licensee notified the NRC that both steam generators were characterized as Category C-3 in accordance with the plant's Technical Specifications (greater than 1% of the inspected tubes defective) due primarily to primary water stress corrosion cracking indications in the portion of the tube within the hot leg tubesheet region.

On slide 5, the primary-to-secondary leakage measured by tritium during the last operating cycle was approximately the same as for the prior operating cycle.

On slide 6, no secondary side pressure tests were performed during the outage due to very low primary-to-secondary leak rates and since there were no repairs performed during the outage that would require a secondary side pressure test.

On slide 9, the eddy current inspection three letter codes were clarified as follows:

CUD - copper deposit, DEP - conductive deposit, DSI - distorted support indication (in the tube), DTI - distorted tubesheet indication (in the tube at the secondary face of the tubesheet), PSI - possible support indication (indicates the tube support plate may be cracked at this location).

On slides 12 and 13 the voltage, depth, and length columns are the maximum voltage, depth, and length observed during the inspection. These maximums may not have all been observed in the same tube (i.e., the maximum voltage may not have been in the same tube that had the maximum depth or length).

On slides 12 and 13, the portion of the tube within the hot-leg tubesheet was inspected with a rotating probe from the tube-end to either 3- or 6-inches above the top of the tubesheet, depending on the height of the sludge pile. The rotating probe inspection distance above the top of the tubesheet is greater than the sludge pile height. Only one axial outside diameter stress corrosion cracking (ODSCC) indication (0.1 volt, 0.09 inch length) was detected in the hot leg sludge pile. This indication was approximately 0.08 inches above the secondary face of the tubesheet. No cracking was detected in the U-bend region of the tubes.

Volumetric cold leg thinning is occurring on the peripheral tubes at the elevations from tubes support plate #1 to tube support plate #5. For this mechanism, indications either greater than 40% through-wall or measuring greater than 1.5 volts are inspected with a rotating probe. If an indication is found at a support outside the "cold leg thinning" region, it is classified as a DSI and inspected with a rotating probe. No crack indications have ever been found on the cold-leg side of the tubes at Prairie Island 2.

Wear indications at the location of the removed anti-vibration bars (AVBs), i.e., now in the free span, are plugged if the degradation exceeds 50% through-wall. Wear indications at the location of the new AVBs are plugged if the degradation exceeds 40% through-wall. These limits are consistent with the unit technical specifications. No rotating probe inspections are performed at wear scars to confirm the absence of cracking at these locations since no free span cracking or cracking at tube support plate elevations has occurred at Prairie Island 2.

On slide 12, circumferential ODSCC at a re-roll expansion was listed as a new mechanism for this unit. The single circumferential ODSCC indication was approximately 0.22 inches in extent, or occurring over 30o of the tube circumference.

On slides 15, the acronyms "AR1," "AR2," and "ARE" represent"additional re-roll 1," "additional re-roll 2," and "additional re-roll elevated." The re-roll distances shown are from the tube end. The required repairs are shown in terms of tubes, not indications, therefore these numbers are not consistent with some of the earlier slides that present information in terms of total indications.

On slides 20 and 21, specific possible loose part (PLP) sorts are performed on the bobbin coil data. All rotating probe data is evaluated for PLP's. The rotating probe sample inspection of the cold leg tubes includes peripheral tubes but is not biased towards the periphery (in order to detect loose parts). New rotating probe PLP indications are investigated during the secondary side foreign object search and retrieval (FOSAR) inspections scheduled for later in the outage. Tubes with new PLP indications that are not able to be visually inspected during the FOSAR (e.g., tubes deeper into the tube bundle), will remain in service if the eddy current data has no indications of tube wear. Sludge lancing is performed on one steam generator each outage and will be performed on SG 22 later in the outage.

Subsequent to the phone call, the NRC staff asked an additional question concerning whether any of the indications in the tubesheet region met the criteria for in-situ leakage testing. The licensee indicated there were only two PWSCC indications in the tubesheet region that exceeded the voltage threshold for leakage testing for flaws in the expansion transition (3.07 volts with a +Point probe). Since these indications had a minimum of 1.0 inch of hard roll above the top of the indication, they did not require in-situ pressure testing.

The licensee assigned a specific leak rate (under steam line break conditions) to these indications in their assessment of tube integrity.

The staff did not identify any issues that required follow-up action at this time; however, the staff asked to be notified in the event that any unusual conditions were detected during the remainder of the outage.

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From: Peter Tam

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