July 19, 2005

Mr. Joseph M. Solymossy
Site Vice President
Prairie Island Nuclear Generating Plant
Nuclear Management Company, LLC
1717 Wakonade Drive East
Welch, MN 55089

SUBJECT: SUMMARY OF CONFERENCE CALL WITH PRAIRIE ISLAND UNIT NUCLEAR GENERATING PLANT UNIT 2 REGARDING 2005 STEAM GENERATOR TUBE INSPECTIONS (MC6756)

Dear Mr. Solymossy:

On May 17, 2005, the U.S. Nuclear Regulatory Commission staff participated in a conference call with Prairie Island Nuclear Generating Plant (Prairie Island), Unit 2 representatives regarding their 2005 steam generator tube inspections. To facilitate this conference call, Nuclear Management Company, LLC (the licensee) provided a preliminary, written summary of the scope and results of their inspection. Enclosed is a summary of the conference call and the Prairie Island Unit 2, refueling outage 23 slides provided by the licensee in support of this call. If you have any further questions, please contact me at 301-415-8371.

Sincerely,

/RA/

Mahesh L. Chawla, Project Manager, Section 1
Project Directorate III
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket Nos. 50-306

Enclosures: 1. Summary of the conference call
2. Prairie Island Unit 2R23 Outage - Slides

cc w/encls: See next page

Prairie Island Nuclear Generating Plant,
Units 1 and 2

cc:

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MAY 17, 2005, CONFERENCE CALL SUMMARY

STEAM GENERATOR TUBE INSPECTIONS

PRAIRIE ISLAND UNIT 2

DOCKET NO. 50-306

On May 17, 2005, the Nuclear Regulatory Commission (NRC) staff participated in a conference call with Prairie Island Nuclear Generating Plant (Prairie Island), Unit 2 representatives regarding the results of their 2005 steam generator tube inspections performed during refueling outage (RFO) 23. The topics discussed during the call are contained in an NRC letter dated April 26, 2005 (ML051090356). A summary of the information provided during the call is discussed below.

The two steam generators at Prairie Island, Unit 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 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, Unit 2 has been approximately 590-degrees Fahrenheit since commencement of initial operation. There are no sleeves installed in the Prairie Island, Unit 2 steam generators as of 2005.

In addition to the depth-based tube repair criteria, the licensee is also 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, Nuclear Management Company, LLC (the licensee) has not found it necessary to implement these criteria since no indications subject to this repair criteria have been identified at Prairie Island, 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. Additional clarifying information and information not included in the document provided is summarized below:

> Both steam generators were characterized as Category C-3 in accordance with the plant's technical specifications due primarily to primary water stress corrosion cracking indications in the portion of the tube within the tubesheet region.

On slide 5, a pressure test of the steam generators is discussed. This pressure test is scheduled for this outage following the replacement of the remaining Alloy 600 explosive plugs. The pressure during the test will be between 100 and 800 pounds per square inch (psi). If a non-plugged tube is observed to be leaking, the tube will be inspected.

On slide 6, no exceptions were taken with the guidelines.

On slide 8, the portion of the tube within the hot-leg tubesheet was inspected from the tube-end to either 3- or 6-inches above the top of the tubesheet. Tubes in the region where the sludge pile is higher were inspected to 6-inches above the top of the tubesheet. The acronym “PSI” stands for “possible support indication.” This is an acronym to indicate that the tube support plate may be cracked at this location. To make sure no cracks are occurring at locations with cold-leg thinning, all cold-leg thinning indications satisfying the criteria on slide 8 are inspected with a rotating probe. No crack indications have been found on the cold-leg side. 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 Unit 2.

On slides 11 and 12 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).

The wear indications at the location of the removed anti-vibration bars (AVBs) are stable (i.e., they are not growing). Wear indications at the location of the removed AVBs are plugged if the degradation exceeds 50 percent through-wall. None of these indications exceed 40 percent through-wall. Wear indications at the location of the new AVBs are plugged if the degradation exceeds 40 percent through-wall. The licensee indicated that these limits are consistent with the technical specifications.

On slide 11, the longest outside diameter stress corrosion cracking indication in the crevice region was listed as 0.52-inch; however, during the call, the licensee indicated that the longest was actually approximately 3-inches long. This 3-inch indication started approximately 0.8-inches below a re-roll and extended through the roll to above the roll by about 1-inch. The voltage associated with the indication was approximately 0.3 volts. This tube was re-rolled approximately 3 cycles ago and has only 1 re-roll.

On slide 12, the 3.53 volt primary water stress corrosion cracking indication at the expansion transition is approximately 0.75-inch long and is located primarily below an intact roll (i.e., only approximately 0.1-inch of the flaw extends into the bottom expansion transition of the re-roll).

On slides 11 and 12, no cracking was found in the U-bend region. The noise levels are monitored in the U-bend region and site-specific noise acceptance criteria are applied (similar to what was used in prior outages). Although the noise levels are not trended (i.e., to determine if one inspection has more noise than the prior inspection), no tubes exceeded the noise acceptance criteria. As a result, no high frequency rotating probe inspections were performed.

On slides 13 and 14, the acronyms “AR1", “AR2", and “ARE” stand for “additional reroll 1", “additional reroll 2", and “additional reroll elevated.” The actual number of additional tubes requiring plugging during the outage (i.e., hot- and cold-leg roll plugs), as listed on slide 14, may change since some of the re-rolls may not be acceptable. If a re-roll performed on an “ARE” tube is unacceptable (i.e., an elevated re-roll), the tube is plugged.

On slide 20, the FOSAR for steam generator 21 is scheduled for later in the outage.

The NRC staff did not identify any issues that required follow-up action at this time; however, the NRC staff asked to be notified if there was any leakage during the secondary side pressure test. Subsequent to the conference call, the NRC staff was notified that there was no identifiable leakage during the secondary side pressure test. The secondary side pressure (approximately 230 pounds per square inch) was held for approximately 4 hours during the test.