January 31, 2003

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

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNIT 1 - SUMMARY OF CONFERENCE CALL WITH NUCLEAR MANAGEMENT COMPANY, LLC REGARDING THE 2002 STEAM GENERATOR INSPECTIONS (TAC NO. MB6393)

Dear Mr. Nazar:

On November 22 and 26, 2002, the Nuclear Regulatory Commission (NRC) staff participated in conference calls with the Nuclear Management Company, LLC (the licensee), regarding the steam generator (SG) tube inspection activities at Prairie Island Nuclear Generating Plant, Unit 1, during refueling outage 22 (RFO-22). The conference calls were strictly voluntary on your part and occurred after the majority of the tubes had been inspected, but before the SG inspection activities were completed. A summary of the conference calls is provided in Enclosure 1 and the handouts provided by the licensee in support of the conference calls is provided in Enclosure 2.

This completes the NRC staff's efforts under TAC No. MB6393.

If you have any questions regarding this matter, please contact me at (301) 415-1446.

Sincerely,

/RA/

John G. Lamb, Project Manager, Section 1
Project Directorate III
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-282

Enclosures: 1. Summary of Conference Calls
2. Licensee Handouts

cc w/encls: See next page

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SUMMARY OF NUCLEAR REGULATORY COMMISSION STAFF

CONFERENCE CALLS WITH NUCLEAR MANAGEMENT COMPANY, LLC

ON NOVEMBER 22 AND 26, 2002

REGARDING STEAM GENERATOR INSPECTION RESULTS AT

PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNIT 1

On November 22 and 26, 2002, the Nuclear Regulatory Commission (NRC) staff participated in conference calls with the Nuclear Management Company, LLC (the licensee), regarding the steam generator (SG) tube inspection activities at Prairie Island Nuclear Generating Plant, Unit 1. On the November 22, 2002, call, the licensee discussed topics based on the agenda that the NRC staff forwarded to the licensee in a letter dated November 13, 2002 (ADAMS Accession No. ML023010607). The licensee provided written material in support of the conference calls (See Enclosure 2 to the letter forwarding this enclosure). Summaries of the conference calls are provided below.

November 22, 2002, Conference Call

The licensee reported that primary-to-secondary leak rates for SGs 11 and 12 before shutdown were less than 1 gallon per day based on the tritium activity and less than 2 gallons per day based on the argon and xenon activities. The licensee did not conduct any secondary side pressure tests because of low leak rates.

With regard to the tube inspection scope, the licensee performed the following examinations:

1. Bobbin coil examination of all the inservice tubes, full length, in both SGs.
2. Rotating probe examination of all the hot leg tubes 3 inches above the tubesheet and full length inside the tubesheet region.
3. Rotating probe examination of 25 percent of the welded sleeves and Alloy 690 plugs (all fabricated by ABB).
4. Supplemental examinations of various bobbin indications using a plus-point coil, including: absolute drift signals; copper deposit; deposit signals; dents with possible indications; dents greater than 5 volts at tube support plate intersections and tubesheets; 25 percent of all free span dents greater than 5 volts; distorted roll indications; distorted support and tubesheet indications; nonreportable indications greater than 1.5 volts at tube support plate intersections (i.e., bobbin signals > 1.5 volts reported during a previous inspection and not identified this outage); manufacture burnish marks; mixed residual signals; nonquantifiable indications; possible loose part indications; and cold leg thinning indications.
5. U-bend region examination using a mid-frequency plus-point coil for all row 1 and 2 tubes and a high frequency plus point coil for the noisy row 1 and 2 tubes.
6. Visual examination of all tube plugs and sleeves.

As of November 22, 2002, the licensee completed about 70 percent of the eddy current data analysis and reported the following findings:

> In SG 11, the licensee detected a total of 9 cold leg thinning indications, 16 anti-vibration bar (AVB) wear indications, 2 wear indications at the location of the old tube lane blocking device, 150 distorted indications at tube support plate intersections, and 37 hot leg tubesheet crevice indications.
>
> In SG 12, the licensee detected 6 cold leg thinning indications, 7 AVB wear indications, 130 distorted support indications at tube support plate intersections, and 152 hot leg tubesheet crevice indications. Only a subset of these indications exceeded the plugging criteria and are scheduled for plugging or repair.

The AVB wear indications range from 8 percent to 44 percent throughwall and there has been no change from previous inspection data. The licensee applies an administrative plugging criterion of 40 percent throughwall to these indications (in lieu of the 50-percent throughwall plugging criterion required by the plant technical specifications (TSs)). These AVB wear indications are caused by the replacement AVBs. The licensee replaced the original AVBs around 1986-1987 to minimize AVB wear with an improved design and corrosion-resistant material. The replacement AVBs are fabricated from stainless steel material.

Both SGs contain tubes with wear scars from the original AVBs. The licensee did not discuss these in detail; however, the licensee did indicate that these wear scars are inspected each outage and a comparison is made to previous inspection data to determine if there is any change to the depth of these AVB wear scars. The licensee indicated that there has been no change, as expected, because the replacement AVBs are no longer in contact with the tube at the wear scar location. The tube wear scars due to the old tube lane blocking device (TLBD) are also not changing, because the device is no longer present. The 50-percent throughwall plugging criterion is applied to the old AVB wear scars and the old TLBD scars.

The cold leg thinning indications were found at the first and third tube-to-tube support plate intersections. The depth of the indications ranged from 2 percent to 55 percent throughwall and the maximum voltage was 2.04 volts. Plugging of these indications is determined based on the criteria in the TSs.

The majority of the distorted indications at the tube-to-tube support plate intersections are located at the first and second hot leg tube support plate intersections and are less than 1 volt as determined from the bobbin coil. The maximum voltage is 1.43 and 1.34 for SGs 11 and 12, respectively. These indications are related to outside diameter corrosion cracking and are inspected and repaired under the voltage-based alternate repair criteria.

The hot leg tubesheet crevice indications are documented in the material provided by the licensee. The indications below the “F*0 Distance” will be left in service in accordance with the F* alternate repair criteria identified in the TSs. The indications that are “within 0.25 inch" of roll transition and “> 0.25 inch” above roll transition will be plugged. The three volumetric indications located above the top of the tubesheet in SG 11 are due to wear from a loose part (a washer), which was removed several cycles ago. The single axial indication located above the top of the tubesheet in SG 11 was selected for in-situ pressure testing (see discussion below). This is not a new degradation mechanism for Prairie Island.

The licensee will either plug or repair tubes that have detectable indications except those indications that have satisfied the alternate repair criteria or tube plugging limits as specified in the plant TSs. The outside diameter stress corrosion cracking indications detected at the tube support plate intersections that have satisfied the voltage-based alternate repair criteria will remain in service. The indications detected in the tubesheet that have satisfied the F-star or elevated F-star alternate repair criteria will remain in service. Any wear indications or cold leg thinning that have satisfied the plugging limits will also remain in service.

The licensee's resolution analysts and/or the independent qualified data analyst reviewed previous inspection data. The licensee reviewed all historical indication-not-found signals, signals located greater than 0.5 inch from the historical call to verify the same tube indication, dent-with-indication signals, manufacturing burnish mark signals, and non-quantifiable indication signals. The licensee also reviewed historical distorted support indications from the bobbin coil probe and "I" code indications at the roll transition, tubesheet, freespan, U-bend and tube support plates from the rotating pancake coil probe. More details on this topic are contained in Enclosure 2 to the letter forwarding this enclosure.

The licensee discussed an issue related to mixed residual signals (MRI). In accordance with Generic Letter 95-05, which the licensee implements as part of the voltage-based alternate repair criteria, the licensee is required to determine which tube-to-tube support plate intersections contain mixed residuals of sufficient magnitude to cause a 1.0-volt indication to be missed or misread. The alternate repair criteria cannot be applied to these tube support plate intersections. In 1997, the licensee implemented the MRI sort (algorithm) in the data analysis and did not find any MRI which would require exclusion of the intersection from the alternate repair criteria. A mixed residual must be greater than 2 volts and have a phase angle of between 10 degrees and 170 degrees to be given an MRI code. During the 1999 and 2001 inspections, the licensee inadvertently left out the MRI sort in its data analysis. This was identified in 2002. In the 2002 inspection, the MRI sort was implemented and the licensee detected one MRI signal in SG 11. Fifty-six percent of the bobbin inspection were complete at the time of the conference call. Inspection of this intersection with a rotating probe had not been completed at the time of the call. The licensee was requested to notify the NRC staff if any intersections with an MRI contained an indication as confirmed by a rotating probe.

With regard to new inspection findings, the licensee detected approximately 30 new dent signals in the row 1 and 2 tubes in SG 11. The dents were located at the 6^{th} and 7^{th} tube support plates on the hot leg and at the 6^{th} tube support plate on the cold leg. The licensee's preliminary assessment indicated that the denting was caused by heat treatment of the u-bend regions of the row 1 and 2 tubes during the previous outage. After reviewing the historical data, the licensee identified the dent signals on the post-heat treatment bobbin data, but the dent signals did not appear in the bobbin data before the heat treatment. The licensee has requested a root-cause analysis from Westinghouse, the vendor who performed the heat treatment. The NRC staff requested the licensee provide a summary of this analysis when it is complete, either in writing or via another conference call. The licensee stated that the final analysis will be complete after plant startup from the refueling outage. The licensee is also inspecting a subset of the new dents with a rotating probe to determine if the denting has caused additional degradation of the affected tubes.

At the time of the call, the licensee identified one in-situ pressure test candidate (a tube with a single axial indication located above the top of tubesheet in SG 11).

The licensee has a contingency plan for tube pulls in accordance with voltage-based alternate repair criteria commitments; however, at the time of the conference call, there was no candidate tube for removal.

The NRC staff concluded the call with the request that the licensee notify the NRC staff if significantly different inspection results were identified during the completion of the inspection.

<u>November 26, 2002, Conference Call</u>

At the request of the NRC staff, a follow-up call was held on November 26, 2002, to discuss several steam generator tube inspection findings that were identified following the conference call held on November 22, 2002. The inspection findings were related to an indication associated with a SG tube sleeve, long axial flaws in the tube within the tubesheet, results of the inspection with a specialized probe of the new dents, and the results of the inspection of the low row u-bends with a rotating probe.

The licensee indicated that it had identified a single volumetric indication (SVI) in the parent tube, behind the sleeve, approximately 0.5 inches above the centerline of the upper welded joint. It appeared to be approximately 0.1 inches in axial and circumferential extent and was approximately 0.19 volts (i.e., barely detectable). The licensee was not able to conclude whether the indication initiated from the inside or outside diameter. The indication was inspected with both a low frequency Plus Point probe as well as a magnetically biased Plus Point probe. Both probes confirmed the indication. This appears to be a new degradation mechanism at Prairie Island, Unit 1.

As a result of identifying this indication in the parent tube behind the sleeve, the licensee expanded their initial inspection scope to incorporate inspection of 100 percent of the installed sleeves with a Plus Point probe. No similar indications were identified. The licensee also reviewed the inspection history associated with this sleeve. The licensee reviewed all inspection data beginning in 1996 when the sleeve was installed through the 2002 refueling outage. The 2002 inspection was the first time the indication was detectable. Lastly, the licensee in-situ pressure tested the sleeved tube to three times the normal operating pressure differential with no leakage.

The licensee concluded that no further actions on the sleeved tubes were necessary based on: the successful completion of the in-situ pressure test; the apparently small size of the indication; the inspection of 100 percent of all installed sleeves; and the fact that no similar indications were identified in the remaining sleeves.

At the time of the call, the licensee had identified two long axial flaws in the tubes within the tubesheet. They were approximately 11 inches and 13.5 inches long and appeared to be very shallow and were believed to be outside diameter stress corrosion cracking. The licensee performed full length tube in-situ pressure testing of these two tubes to main steam line break pressure differentials with no leakage. Post in-situ eddy current testing showed some change in signal, which is typical for this type of degradation. The licensee indicated that this was not a new degradation mechanism at Prairie Island, Unit 1. The licensee typically identifies 3 to 4 long axial indications in the tubesheet every outage, and in fact, the licensee pulled a tube for destructive examination in 1985 containing an axial flaw 18 inches long.

As discussed above, the licensee identified a population of new dents during the SG tube inspections for refueling outage 22. The licensee believes that the new dents developed as a result of the heat treatment of the low row u-bends during the previous refueling outage. The licensee inspected all new dents greater than 5 volts, and inspected a subset of the new dents less than 5 volts. These inspections were complete at the time of the November 26, 2002, conference call. No tube degradation was identified in any of the new dents.

The licensee indicated that the inspections of the low row u-bends with a rotating probe were complete. No degradation was identified as a result of these inspections.

The NRC staff did not identify any other issues requiring follow-up.