February 17, 2004

Mr. Dale E. Young, Vice President
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SUBJECT: CRYSTAL RIVER UNIT 3 - SUMMARY OF CONFERENCE CALLS WITH FLORIDA POWER CORPORATION REGARDING THE FALL 2003 STEAM GENERATOR INSPECTION (TAC NO. MC0965)

Dear Mr. Young:

On October 14, 15, 23, and 28, 2003, the Nuclear Regulatory Commission (NRC) staff participated in conference calls with Florida Power Corporation (also doing business as Progress Energy-Florida) regarding the steam generator (SG) tube inspection activities at Crystal River Unit 3 during the fall 2003 refueling outage 14. 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.

This completes the NRC staff's efforts under TAC No. MC0965.

If you have any questions regarding this matter, please contact me at (301) 415-2020.

Sincerely,

/RA/

Brenda Mozafari, Senior Project Manager, Section 2
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-302

Enclosures:
1. Summary of Conference Call
2. Teleconference Participants
3. Licensee Facimile

cc w/enclosures: See next page

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SUMMARY OF CONFERENCE CALLS

WITH PROGRESS ENERGY

REGARDING FALL 2003 STEAM GENERATOR INSPECTION RESULTS

AT CRYSTAL RIVER UNIT 3

On October 14, 15, 23, and 28, 2003, the Nuclear Regulatory Commission (NRC) staff participated in a series of phone calls with Florida Power Corporation representatives (doing business as Progress Energy - Florida) to discuss the results of its 2003 steam generator (SG) tube inspections at Crystal River Unit 3. To facilitate the discussion on October 14, the licensee provided some written information on steam generator design, examination scope, and results to date. Additional information in support of discussions on cracking in the tube ends was provided by the licensee subsequent to the October 14 call. The material provided by the licensee is attached to this conference call summary.

A summary of the phone calls is provided below. Crystal River 3 has two once-through steam generators (OTSGs). Primary-to-secondary leakage was averaging 2.5 gallons per day prior to the shutdown for the 2003 outage, which is consistent with the leakage observed during the previous cycle. No clear source of this leakage was identified during the 2003 SG tube inspections. Given the low level of leakage, no secondary side pressure tests were conducted during the outage.

During the October 14 call, the licensee indicated that it had, or was planning to, deviate from Revision 6 of the EPRI Steam Generator Examination Guidelines, as follows:

- The licensee used a technique to inspect portions of the tube within the lower tubesheet (LTS) region that did not meet the probability of detection guidance contained within the EPRI guidelines. Specifically, the licensee planned to use a bobbin coil to: (a) inspect the entire length of tube within the LTS if the tube was outside the sludge pile region (i.e., the region where the sludge height did not exceed 1 inch) and (b) inspect the portion of the tube from 8 inches below the secondary face of the LTS to the lower tube end for all tubes within the sludge pile region. The licensee indicated that another OTSG owner had performed an evaluation for the use of the bobbin coil at these locations. In addition, the licensee's basis for concluding that the bobbin coil provided adequate detection capability in this region was demonstrated by a comparison of eddy current signals in the LTS to similar indications in the upper tubesheet (UTS). This study indicated that the noise levels and other eddy current signal characteristics in the LTS were comparable to those in the UTS. Lastly, the licensee stated historical data from the industry that compared the relative detection capabilities of the bobbin coil and rotating coil probes in this region supported this deviation from the EPRI Guidelines. The licensee indicated that no EPRI Appendix H or peer review of this technique was planned at this time, but that it was qualified by the site for use at Crystal River. The NRC staff did not review the technical basis for this deviation in detail during the call; however, the licensee was requested to notify the NRC staff if more than a few indications were detected within the LTS crevice region. Past inspections had not revealed extensive degradation within this region.

- The licensee was not planning to inspect the LTS tube ends and roll transitions with a probe capable of detecting cracks as recommended by the EPRI Guidelines when the extent of cracking in the UTS reaches certain limits. The licensee's justification for this deviation was based on previous inspection results in which no cracks were identified and a B&W Owners Group study that indicated that cracking in the LTS roll transition is improbable.

- A secondary side visual exam was not performed as recommended by the industry guidelines since OTSGs are less susceptible to loose parts damage than other designs.

- Data quality verification was not performed in accordance with the industry guidelines since implementation requires the use of a specific type of software that was not being used at the plant during the outage.

- The certificates of conformance (verifying that probe manufacturing tolerances were within certain limits) were not available for all probes since some of the probes used during the outage were purchased before this requirement was incorporated into the guidelines.

- In-situ pressure testing was not used to verify tube integrity for indications in the UTS tube ends and roll transitions (original roll and/or re-roll transitions) since analytical methods were used to calculate the amount of leakage expected during postulated accident conditions.

In addition to the deviations to the SG examination guidelines, the licensee also indicated that it took seven deviations to the EPRI chemistry guidelines during the cycle. The items mentioned included lower dissolved reactor coolant system hydrogen levels, measuring feedwater pH at 25^{o}C, changing the frequency of feedwater suspended solid measurements, continuous monitoring of feedwater sodium, analysis of feedwater silica, and changing the feedwater concentration action levels. These deviations were not discussed in detail since their effect on the SG tubes, if significant, would be evident from the inspection results.

At the time of the initial call, the licensee had completed 95 percent of the bobbin coil examinations, and examination with the rotating probes were in progress. The inspection scope included a bobbin coil inspection of 100 percent of the tubes from tube-end to tube-end. In addition, a rotating probe (+Point^{TM}) was used to inspect several regions of the tube, including but not limited to the following:

34 percent of the tubes in the sludge pile (kidney region) from 4 inches above the secondary face of the LTS to 8 inches below the secondary face of the LTS

34 percent of the non-sleeved tubes immediately adjacent to the sleeved tubes in the lane/wedge region

20 percent of the dents greater than or equal to 2.5 volts that were located between the LTS + 4-inches to the UTS

100 percent of the dents in tubes adjacent to tubes that had explosive plugs installed

the roll transitions in the UTS for 100 percent of the tubes

the rolled joints (upper roll, mid-roll, lower roll) in 34 percent of the installed sleeves

100 percent of Alloy 600 rolled plugs

all LTS roll transitions that did not receive a stress relief after rolling

178 tubes containing intergranular attack (IGA) in the first tube span

During the call on October 14, 2003, the licensee stated that no new degradation mechanisms had been detected as of yet. In addition, it indicated that when certain types of indications were detected with a bobbin coil during the 2003 outage that it compared the 2003 data to data acquired in 1997. This was performed to determine if any change in the bobbin coil signal was evident. If a change were to occur, the licensee would determine whether to perform additional examinations with a rotating probe to further characterize the nature of the indication.

The dominant tube degradation mechanism detected during the 2003 outage was axial tube end cracking in the UTS. None of the tube end cracks extended beyond the Inconel™ cladding on the primary face of the UTS. Approximately 600 axial and approximately 60 circumferential tube end crack indications were detected in the UTS. Approximately 100 tubes contained roll/reroll indications in the UTS. In addition, steam generator B contained 7 volumetric (0.15 volt maximum) indications near the tube end in the UTS. The licensee planned to repair (reroll) or plug tubes with either circumferential or volumetric indications. Reroll repairs were performed on almost 450 tubes in the UTS. No tubes met the EPRI guideline criteria for in-situ pressure testing. No sleeve repairs were planned. No loose parts had been identified by either the bobbin coil examination or the loose part monitors during the most recent operating cycle.

The licensee stated the Crystal River SGs contain a total of 77 welded plugs with five different welded plug designs. The remotely welded plug with the most limiting remaining service life has 17 heat-up and cool-down cycles remaining before replacement would be necessary. Crystal River will continue to monitor plant cycles to ensure the plant would not exceed the replacement schedules recommended by Framatome for the B&W Owners Group.

The licensee identified nine tubes that were potentially susceptible to a tube severance similar to that observed at another plant. These nine tubes were identified using criteria developed by Framatome. These nine tubes were in a high cross flow velocity region and had their original Alloy 600 plugs replaced with Alloy 690 plugs. Instead of removing a plug from these tubes and inspecting them to verify that they were not severed and/or were not filled with water, the licensee elected to inspect, plug, and stabilize the surrounding tubes that could be affected if the plugged tube failed. As a result, the licensee plugged and stabilized six tubes in SG A and 28 tubes in SG B to surround these nine tubes.

Consistent with past inspections, the licensee detected intergranular attack (IGA) along the length of tube between the secondary face of the lower tubesheet and the first tube support plate (i.e., in the first span) in SG B. This degradation was detected with high frequency bobbin coil and +Point™ probes. Two tubes had IGA indications in the first span, which measured greater than 40 percent through-wall; five tubes had IGA indications, which grew by more than 10 percent since the prior outage; and one tube appeared to have a new indication. All eight tubes were plugged.

In addition to the typical questions (ML032890206) addressed by the licensee in support of the 2003 outage call, the NRC staff requested follow-up information from a request for additional information (ML023470215) developed during a review of the 2001 SG inspection report since these topics had potential bearing on the current inspection. The licensee addressed all follow-up questions during the October 14 call but indicated additional time would be needed to verify main steam line break (MSLB) leakage values for the 2001 operational assessment (OA) provided in the RAI response. Licensee responses related to the 2001 outage report RAI will be addressed in the 2001 SG inspection report review.

At the conclusion of the October 14, 2003, call, the NRC staff requested the licensee notify the NRC if any of the following conditions occurred: new degradation modes were identified, more than three indications were detected in the lower tubesheet sludge pile region, cracking was detected in dented regions, or leakage occurred during any in-situ pressure tests.

Following the initial phone call, the licensee notified the NRC that a tube end crack was detected in the LTS adjacent to a tube that contained an explosive plug that had been repaired with a welded plug. This tube was selected for examination since tubes adjacent to explosively plugged tubes may have denting, which may result in increased susceptibility to cracking. After this crack was identified, the licensee implemented a sampling plan with buffer zones that eventually expanded into a rotating probe inspection of all tubes from the tube end to the upper transition of the tube roll in the LTS in each SG. As a result of these inspections, approximately 300 crack indications were detected near the LTS tube ends during the 2003 outage. Of these, approximately 200 were circumferentially oriented, and the remainder were axially oriented. The cracks in the LTS tube ends were found in the outermost 18 rows of tubes (i.e., tubes near the periphery). The reason for the preferential distribution of the LTS tube end cracks towards the periphery of the tube bundle was not known. All tubes containing a circumferential indication were repaired by re-roll. This is the first time that tube end cracking had been detected in the LTS of an OTSG.

The licensee subsequently contacted the NRC staff to respond to a question raised during the initial phone call regarding its prior cycle calculation of primary-to-secondary leakage during postulated accident conditions. The licensee indicated an incorrect value was provided in one of its reports due to a breakdown in communications among vendors concerning the leakage attributed to tube end cracking. The correct value was communicated to the NRC in the 2001 outage Mode 4 Report. This condition was entered into the licensee's corrective action program to ensure appropriate corrective actions are taken to prevent recurrence.

During a conference call on October 28, 2003, the NRC staff and the licensee discussed the licensee's estimate of the amount of primary-to-secondary leakage expected to occur under postulated accident conditions based on the 2003 inspection results. The licensee indicated that if a postulated accident had occurred just prior to the 2003 outage, a conservative estimate of the amount of leakage would be 1.029 gallons per minute (gpm) if the accident were associated with SG A and 1.241 gpm if the accident were associated with SG B. These calculated values exceed the 0.856 gpm Crystal River 3 leakage limit. The licensee indicated that its projected leakage following its next cycle of operation was well within the limits since it repaired many of the tubes with cracks. The implications of the condition monitoring leakage values will be addressed during the NRC staff's review of the report Crystal River is required to submit prior to ascension into Mode 4.

Other than the items discussed above, the NRC staff did not identify any concerns during the phone call regarding the licensee's inspection program or the results obtained.

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