September 1, 2005

Mr. Mark B. Bezilla
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SUBJECT: DAVIS-BESSE NUCLEAR POWER STATION, UNIT 1 - SUMMARY OF CONFERENCE CALLS RE: 2005 STEAM GENERATOR TUBE INSPECTIONS (TAC NO. MC5606)

Dear Mr. Bezilla:

On January 13, 28 and 31, and February 3, 2005, the Nuclear Regulatory Commission staff of the Materials and Chemical Engineering Branch participated in conference calls with Davis-Besse Nuclear Power Station, Unit 1 representatives regarding your 2005 steam generator tube inspection activities. Enclosed for your information is a summary of the conference calls.

Sincerely,

/RA/

William A. Macon, Jr., Project Manager, Section 2
Project Directorate III
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-346

Enclosure: As stated

cc w/encl: See next page

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DAVIS-BESSE NUCLEAR POWER STATION, UNIT 1
2005 MID-CYCLE OUTAGE
STEAM GENERATOR TUBE INSPECTION ACTIVITIES
CONFERENCE CALL SUMMARIES

January 13, 2005 Pre-Inspection Conference Call

On January 13, 2005, the Nuclear Regulatory Commission (NRC) staff conducted a pre-inspection phone call with Davis-Besse Nuclear Power Station, Unit 1 (DBNPS, the licensee) to discuss its inspection plan for the upcoming steam generator (SG) tube inspections during its Cycle 14 mid-cycle outage. DBNPS has two Babcock and Wilcox once-through SGs. The tubes are sensitized Alloy 600 in the mill annealed condition. The last inspection of the SG tubes was completed on March 9, 2002. The NRC issued a license amendment on February 26, 2004 (Agencywide Documents Access and Management System Accession No. ML040580026), regarding a one-time extension to the SG tube inservice inspection frequency. This amendment extended the 24-calendar month inspection frequency in Technical Specification (TS) Surveillance Requirement 4.4.5.3.a by approximately 12-calendar months. For most of the first 24-calendar months since the previous SG tube inspections, the licensee was in an extended shutdown. As a result, the SGs were not exposed to the high temperature conditions generally required for corrosion-induced degradation of the SG tubes.

In support of the phone call, the licensee provided a written summary of the planned SG tube inspections for the upcoming mid-cycle outage. Although the inspection was going to take place during a mid-cycle outage, the licensee indicated that it was a complete SG inspection performed in accordance with the TS requirements. Additional clarifying information and information not included in the documents is summarized below:

- At the time of the last inspection, the plant had operated for 15.8 effective full power years (EFPY). At the time of the mid-cycle inspection, the plant is expected to have run an additional 0.8 EFPY.

- In the "2A" SG, there are 562 tubes plugged and 199 sleeves installed. In the "1B" SG, there are 161 tubes plugged and 212 sleeves installed.

- In the "2A" SG, there are 32 tubes repaired by rolling. In the "1B" SG, there are 8 tubes repaired by rolling. All of these reroll repairs were performed in 2002.

- All sleeves were installed in the 1994-1996 timeframe in the lane/wedge region as a preventive measure against high-cycle fatigue. All sleeves are manufactured from Alloy 690 thermally-treated material. The licensee has no plans to install sleeves this outage.

- The licensee will perform an inspection of 21 percent of the sleeves full length with a rotating probe. This inspection will continue to approximately 6 inches below the bottom of the sleeve. The licensee is inspecting the remaining 79 percent of the sleeves with a rotating probe from the lower roll to 6 inches below the bottom of the sleeve. The inspections below the sleeve roll (and below the sleeve) are for the purposes of detecting any potential parent tube defects in this region since the sleeve interferes with the ability to detect degradation in the parent tube with the bobbin probe.

- The licensee planned to deplug, inspect for internal water, stabilize and re-plug 6 tubes in the "2A" SG. In 2002, possible cracks were identified in the welded plugs in the lower tubesheet (the plugs had been installed prior to initial plant operation). The plugs were machined out and the tubes were inspected with a bobbin probe. Small holes were identified in the tube approximately 2 inches below the upper tubesheet secondary face (i.e., the freespan region). The holes were caused by a TIG torch. The tubes were re-plugged, but were not stabilized. Based on current DBNPS inspection/repair criteria, these tubes are now required to be stabilized prior to re-plugging which is the basis for the upcoming outage activities.

- Forty-two sleeves are being examined full length with a bobbin coil probe because inner-diameter surface scratches were previously identified in these sleeves. All of these sleeves are in the "1B" SG. Some of the scratches were approximately 11-12 inches long. The licensee stated that changes in the scratches can be detected via the bobbin examination. The licensee attributed the scratches to the sleeve installation process. Some of these scratches will be examined with a rotating probe during the outage.

- NRC staff asked whether the licensee planned to inspect suspected wear indications (initially detected via a bobbin coil probe) with a rotating probe in order to differentiate between a volumetric indication (i.e., wear) and crack-like indications. The licensee stated a large number of suspected wear indications had been inspected with a rotating probe during previous inspections and that a smaller sample would be inspected with a rotating probe during the upcoming inspection. The NRC staff indicated they would like to discuss this issue again during the outage conference call to understand the final scope of rotating probe inspections, the inspection results, and scope expansions, if any.

- Dents are recorded at a threshold of 2.5 volts.

- During the 2002 SG inspection, 40 repair rolls in the upper tubesheet were inspected from the upper tube end through the bottom of the repair roll.

- The licensee planned to inspect the roll expansions and tube ends of 21 percent of the tubes in the lower (i.e., cold-leg) tubesheet with a rotating probe based on industry experience identifying degradation in this region. The 21 percent sample was mostly focused on peripheral tubes (i.e., 41 inches radially outward from the center line of the bundle). The 21 percent sample included some tubes in the interior of the tube bundle. Rotating probe inspections were not previously performed in this region at DBNPS.

  The licensee stated that if one crack-like indication was identified in the lower roll, they planned to inspect with a rotating probe the lower rolls of 100 percent of the tubes in the affected SG. With respect to the inspection of the tube end region, the licensee predefined the initial 21 percent sample into TS categories 1S, 2S and 3S samples. TS sample expansion requirements would be followed. All indications found in the tube ends will be repaired or plugged since the tube end cracking (TEC) alternate repair criteria has not been approved at DBNPS.

- The licensee took an exception to the Electric Power Research Institute (EPRI) Steam Generator Examination Guidelines associated with their inspection of the sludge pile region (i.e., the region surrounding the secondary side of the lower tubesheet). The licensee planned to inspect approximately 500 tubes per SG with a rotating probe (i.e., approximately 23 percent sample of the sludge pile region). The inspection was to range from a minimum of 3 inches above to 3 inches below the secondary face of the lower tubesheet, which bounds all previously discovered defects in this region at DBNPS. The licensee planned to inspect an additional 3 inches into the tubesheet if a defect was detected within 0.4 inches of the bottom of the original inspection extent. Lastly, if a flaw was detected via the rotating probe examination and missed via the bobbin probe examination, or if greater than three flaws were detected in the sludge pile region in a single SG which exceeded the analysis assumptions, the inspection scope would be expanded. (Note: the licensee believes the bobbin probe detection capability is adequate for this region and performs rotating probe examinations as verification of this assumption.)

  The licensee indicated that the past three outage inspections of this region ranged from a minimum of 4 inches above to 16 inches below the secondary face of the lower tubesheet. Degradation was not detected more than 3 inches below the secondary face of the lower tubesheet.

- Rotating probe inspections in the upper tubesheet will be from the tube end through the reroll. The inspection data from the original roll (in rerolled tubes) will be evaluated to determine the growth rate of the "repaired" indications. A 1-inch defect free zone is needed between the original roll and the reroll.

- If a loose part is identified via eddy current inspection, a secondary side visual examination of the affected region will be performed. The licensee stated that they will plug all tubes with wear indications from loose parts.

January 28, 2005 Outage Conference Call

On January 28, 2005, the NRC staff participated in a conference call with the licensee to discuss the ongoing SG tube inspection activities at DBNPS. In support of the conference call, the licensee provided written material. Additional clarifying information and information not included in the documents is summarized below:

- At the time of the conference call, the SG inspections and analyses were 90 percent complete (the remaining 10 percent of the inspections consisted mainly of special interest inspections with a rotating probe).

- Three axial indications were identified in the "2A" SG in the upper tubesheet roll transitions. Two of these indications were inspected with a rotating probe in 2000 and one was inspected in 1998 with a rotating probe. A review of this historical data indicated no degradation was present at that time. As a result, the scope of inspection with a rotating probe in the upper tubesheet roll expansions and tube ends was increased to 100 percent in the "2A" SG. The NRC staff questioned how the licensee intended to complete the condition monitoring/operational assessment (CM/OA) for this degradation mechanism in the "1B" SG since less than 100 percent of the tubes were to be inspected in this region of the "1B" SG. The licensee stated that: 1) this analysis hasn't been performed yet; 2) they have inspected 100 percent of this region in the "1B" SG between the current and last outage; 3) the "1B" SG typically has had less primary water stress corrosion cracking than in the "2A" SG; and, 4) they plan to inspect 100 percent of the tubes in this location in the next refueling outage (Cycle 14). Therefore, the licensee indicated they would have sufficient information to complete the CM/OA.

- Eleven circumferential indications were identified in the upper tubesheet tube end in the "2A" SG. The indications were in the heat-affected zone and all were above the carbon steel/cladding interface. Some of these locations had been inspected in 2002 (Cycle 13). The licensee stated that a look-back analysis of the previous outage data indicated that the majority of these indications were present at that time. The licensee indicated that due to improved probe alignment (based on the use of a different snorkel mast) and the use of rotating probes qualified to Revision 6 of the EPRI Steam Generator Examination Guidelines, the quality of their inspection had increased and this improved the ability to detect these indications.

- The licensee indicated that 100 percent of wear scars detected with a bobbin probe would also be inspected with a rotating probe.

- In-situ pressure testing was not planned, tube pulls were not planned, indications were not identified in the sleeves, and freespan cracking was not observed.

- No flaws were identified in the rerolls in the upper tubesheet. No loose parts were reported. No indications were identified in the sludge pile region. Three tubes were to be plugged due to noise which could potentially mask a flaw. Inspections in the lower tubesheet were ongoing. No indications had been identified in this region yet. Deplugging and dewatering of the tubes had not yet been performed. Profilometry will be done on these tubes.

- The licensee decreased the threshold voltage for reporting dents to 0.5 volts for all dents located at the 15S tube support plate and higher in the periphery of the tube bundle. The reason for this change was that during their 2002 outage (Cycle 13), they had identified a small outside diameter stress corrosion cracking indication in a dent measuring less than 2.5 volts. This indication was found with a bobbin coil probe. The dent inspection was ongoing, but no indications had been identified in this region yet.

- Remotely welded plugs are installed in the DBNPS SGs. They are analyzed for 33 thermal cycles. The number of thermal cycles are tracked by the licensee and the SG engineers are notified when the number of actual cycles reaches 75 percent of the allowable. This limit has not been reached for any plug yet.

- No volumetric indications (other than wear) were reported. Such volumetric indications had been detected in the past, primarily in the "2A" SG between the fourth and seventh tube support plates. These indications are repaired on detection. The voltages associated with newly identified volumetric indications has been getting smaller as time progresses.

- A total of 40 tubes had been rolled due to TEC. A review of the indications that caused the tubes to be rerolled indicated no change between 2002 (Cycle 13) and this outage (i.e., approximately 0.8 EFPY).

- Fifty-four new tube end indications were predicted to be observed during this outage in the upper tubesheet. However, a total of 64 tube end indications were detected. This under prediction was attributed to improvements in detection.

- The secondary face of the lower tubesheet was pressure washed.

- NRC staff requested that the licensee notify them if any of the following conditions present themselves as the SG inspections are completed: lower tube end flaws; roll transition cracking in the "1B" SG; crack-like indications are identified in areas not previously identified at DBNPS; in-situ candidates are identified; and, if unusual or unique results are identified.

January 31 and February 3, 2005 Outage Conference Calls

On January 31 and February 3, 2005, the NRC staff participated in conference calls regarding the ongoing SG tube inspection activities at DBNPS at the request of the licensee. In support of the January 31, 2005, conference call, the licensee provided written material. Additional clarifying information and information not included in the documents is summarized below:

- The licensee discovered that a shop reroll (SRR) had been installed, during original manufacturing of the SGs, above the roll in the lower tubesheet in almost all the SG tubes (i.e., in all but 102 tubes). They were not previously aware of this detail (i.e., they believed there was only one roll in the lower tubesheet based on bobbin coil inspection results). The tubes were rerolled because there was not good control of the length of the original roll in the lower tubesheet and most were too short. This may have been a result of measuring the length of the roll from the tube end rather than from the bottom of the tubesheet (i.e., the distance the tube end protrudes from the bottom of the tubesheet can vary from one tube to the next). The tubes were rerolled prior to the annealing of the vessel.

  Based on the maintenance records, all of the tubes were supposed to have additional rolls installed. However, 102 did not have the SRR. The licensee indicated that 46 of the 102 tubes without a SRR contained rolls less than 1 inch in length. The shortest roll was 0.75 inches. The licensee indicated that despite this condition, the tube would have been capable of performing its intended function (i.e., maintain structural and leakage integrity under a hot-leg large break loss of coolant accident (LBLOCA)) due to the presence of the seal weld.

  Axial indications were identified in heel of the SRR in a total of 30 tubes in the "1B" SG. The licensee indicated the degradation was most likely caused by higher residual stresses in the SRR (i.e., higher than in the original reroll). They have been inspecting both rolls in the lower tubesheet, are identifying all indications in this region and are plugging on detection. (The licensee initially attempted to install another reroll above the original roll, or SRR, to enable them to leave the tube in-service. However, this process was not successful because there was tube springback due to the sludge and the roll wasn't acceptable.

Therefore, the licensee plugged 34 tubes with a short original roll and 30 tubes with a crack in the SRR.) The axial indications discussed above were not detected via the bobbin probe, however, they were also very small.

They increased the inspection scope to encompass 100 percent of the rolls and SRR in the lower tubesheet in the "1B" SG. They are inspecting 21 percent of the rolls and SRR in the lower tubesheet in the "2A" SG. In addition, they performed a computer data sort on data collected with a bobbin probe to ensure they identified all tubes with SRRs. All of the lower tube end indications are in the "1B" SG while most of the upper tube end indications are in the "2A" SG.

The licensee planned to notify other licensees with original once through steam generators (OTSG) regarding the presence of the SRRs. However, they did not anticipate other licensees would find the same conditions (or at least not as many affected tubes), because DBNPS was the last OTSG owner to inspect this region of the tube with a rotating probe.

- Given the circumstances above, the NRC staff questioned why the licensee had not detected the SRRs previously in the course of analyzing the bobbin data. The licensee indicated that some of the primary and/or secondary analysts (contractors) were aware of the presence of a second roll, however, the analysts did not report this to the licensee because it wasn’t flaw-like and was considered to be part of the SG design, and not abnormal eddy current responses. Some analysts were not aware of the presence of a second roll because the gain setting the eddy current analysts were required to utilize caused the signal from the roll expansions to disappear off the screen (i.e., it was too large).

  The NRC staff questioned whether there could be other, unique, conditions present elsewhere in the SG tube that analysts did not bring to the licensee’s attention. The licensee indicated that after the outage, they planned to investigate construction records for other unusual design characteristics. The NRC staff encouraged the licensee to review the analysis guidelines to ensure it prompted analysts to report unusual/anomalous conditions, even if flaw-like indications aren’t evident.

- Groove intergranular attack (IGA) was identified in both "2A" and "1B" SGs. All the indications were detected with a bobbin probe. None of the indications challenged tube integrity. The largest IGA, which was in the freespan, was determined to be present during the 2002 outage and had not changed in size.

- The licensee deplugged six tubes during the outage and found one of these tubes to contain water (i.e., an estimated 1.9 liters of water was in the tube, and 3.0 liters is considered full). There were no associated diametral changes. There were no flaws in the tube to explain the presence of the water; therefore, the licensee concluded that the water had most likely leaked into the tube through the plug to tube joint. The plug is leak limiting and was installed in 1993. The tube with the water passes through a broached hole support plate rather than a drilled hole support plate. The tube was de-watered.

- A volumetric indication was identified in the "2A" SG between the 15S tube support plate and the secondary face of the upper tubesheet. This was coded as an non-quantifiable indication based on the bobbin inspection and had been identified during several previous SG inspections. The licensee indicated that it was located where an alignment pin (dowel pin) was once present. An internal auxiliary feedwater header sat on the alignment pin. The volumetric indications increased slightly in size during the current outage so the licensee elected to plug the tube.

- Inner-diameter intergranular attack (IDIGA) was identified in several locations. The licensee indicated that a similar indication had been identified in a roll transition during the previous outage and that the destructive examination of a tube pulled in 1996 identified the presence of a small band of IDIGA (i.e., 3 percent throughwall).

- Lastly, the licensee verbally notified the NRC of several circumstances based on license condition requirements.

    1. No circumferential indications were identified in-board of the reroll repairs.

    2. Circumferential indications were identified in the original roll and heat-affected zone/weld region. Fourteen indications were identified in the "2A" SG in the hot leg. Eleven of these were in a seal weld with no reroll and three of which were in tubes that had been re-rolled. Twenty-nine indications were identified in the "1B" SG in the cold leg. Twenty-eight of these were located in the heel of the SRR and one of these was located in a seal weld with no reroll.

    3. The licensee calculated the best estimate LBLOCA leakage to be 0.66 gallons per minute (gpm) in the "1B" SG and 0.06 gpm in the "2A" SG which is below the site limit of 1.0 gpm.