March 31, 2006

Mr. Joseph E. Venable
Vice President Operations
Entergy Operations, Inc.
17265 River Road
Killona, LA 70066-0751

SUBJECT: WATERFORD STEAM ELECTRIC STATION, UNIT 3 - SUMMARY OF MAY 2005 DISCUSSIONS OF STEAM GENERATOR TUBE INSPECTIONS (TAC NO. MC6047)

Dear Mr. Venable:

On May 2, 9, 13, and 25, 2005, the Nuclear Regulatory Commission (NRC) staff participated in conference calls with Entergy Operations, Inc (Entergy) representatives regarding the 2005 steam generator tube inspections at Waterford Steam Electric Station, Unit 3. The NRC staff's summary of these calls, along with the information supplied by Entergy representatives in support of these discussions, is enclosed. The NRC staff did not identify any issues that would warrant preventing the plant from starting-up following its 13th refueling outage.

Sincerely,

/RA/

Mel B. Fields, Senior Project Manager
Plant Licensing Branch IV
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-382

Enclosure: As stated

cc: See next page

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OFFICE	LPL4/PM	LPL4/LA	EMCB/BC*	LPL4/BC
NAME	MFields	DJohnson	LLund	DTerao
DATE	3/30/06	3/31/06	07/07/05	3/31/06

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ENTERGY OPERATIONS, INC.

DOCKET NO. 50-382

WATERFORD STEAM ELECTRIC STATION, UNIT 3

SUMMARY OF MAY 2005 DISCUSSIONS ON STEAM GENERATOR TUBE INSPECTIONS

On May 2, 9, 13, and 25, 2005, the NRC staff participated in conference calls with Waterford Steam Electric Station, Unit 3 (Waterford 3) representatives regarding their 2005 steam generator tube inspections during refueling outage (RF) 13. A summary of the information provided during these calls is provided below. Information supplied by Entergy Operations, Inc. (the licensee) representatives in support of these calls can be found in the NRCs Agencywide Documents and Access Management System, Accession No. ML060730185.

Waterford 3 has two Model 3410 steam generators designed and fabricated by Combustion Engineering. The mill annealed Alloy 600 steam generator tubes have an outside diameter of 0.750-inch and a nominal wall thickness of 0.048-inch. Each steam generator contains 9,350 tubes. The tubes are explosively expanded for the full depth of the tubesheet at each end and are supported by a number of carbon steel lattice grid (i.e., eggcrate) tube supports, diagonal bars (also referred to as batwings), and vertical straps. The tubes in rows 1 through 18 are U-bends and the tubes in rows 19 through 147 are square bends. Waterford 3 is authorized to repair tubes by sleeving; however, no sleeves are currently installed in the steam generators. There are no alternate repair criteria (i.e., other than the 40% through-wall plugging limit) approved for the plant.

The May 2, 2005, discussions focused on the topics provided to Waterford 3 by the NRC. These topics and the plant's response (based on the information available at the time of the call) are attached to this summary. Additional clarifying information and information not included in the document provided is summarized below:

> The results of the inspection were consistent with expectations. For example, approximately 180 tubes in steam generator 1 and 60 tubes in steam generator 2 were expected to require plugging and currently 113 tubes in steam generator 1 and 50 tubes in steam generator 2 are expected to be plugged.
>
> As a result of classifying approximately 106 tubes in steam generator 1 as defective, the steam generator was classified as Category C-3 in accordance with the plant's technical specifications and the NRC was formally notified of these results.
>
> A small primary-to-secondary leak has been present for two cycles in steam generator 1. There was no evidence of boric acid or other visual signs that a plug was leaking. The leak is relatively stable, and the condition has been entered into the plant's corrective action program. During RF 14, a secondary side pressure test is scheduled to assist in identifying the source of the leak.

The Electric Power Research Institute guidelines are used to screen flaws for determining whether they should be pressure/leak tested in-situ.

To identify loose parts at the cold-leg top of tubesheet region, a turbo mix is used to evaluate the bobbin coil data for wear induced by loose parts.

During RF 12, full chemical cleaning, sludge lancing, and secondary side inspections were performed in both steam generators. Typically, secondary side inspections are performed every other outage at Waterford 3. Approximately 40 possible loose part indications were identified by eddy current inspection on the hot-leg side of steam generator 1 in RF 13. All of these possible loose part indications are located near the top of the tubesheet. Six of the 40 indications are located in the periphery. Based on these results, a foreign object search and retrieval (FOSAR) is being performed in steam generator 1 to investigate the six possible loose part indications in the periphery. The results from this effort will be evaluated to determined the need to perform FOSAR in steam generator 2. In addition, the results will be used to assist in assessing the significance of the other possible loose part indications not visually inspected. The possible loose parts in the steam generator were entered into the corrective action program.

Repairs are being performed in both steam generators on the feedline thermal liner. This was the only secondary side steam generator maintenance planned for the outage.

There is one tube with wear associated with a loose part. This tube and a neighboring tube will be plugged and stabilized.

Dented diagonal strap locations with voltages greater than 2 volts were included in the 20-percent rotating probe sample.

The term “over expansions” at Waterford 3 is used to indicate that a tube is bulged. All over expansions are located above the top of the tubesheet (e.g., the tube is bulged due to explosively expanding the tube above the top of the tubesheet or the tube is bulged at a location for another reason).

No crack indications were found coincident with historical wear scars (i.e., bobbin indications attributed to wear in prior inspections) in either steam generator. However, three new bobbin indications (initially attributed to wear based only on bobbin data) were inspected with a rotating probe and identified as cracks rather than wear. These indications were located at the vertical straps in the batwings and were all located in steam generator 2. As a result, 100-percent of the historic wear scars in steam generator 2 were inspected with a rotating probe. No cracks were found in these wear scars.

The axial cracks found in the tubes at the location of the vertical straps were very short and had small amplitudes. The indications measured approximately 0.2 to 0.25 volts with a bobbin coil. In addition, they could be detected (with hindsight) in the 2003 bobbin data.

The axial indications located above the hot-leg, top of tubesheet region were in the sludge pile (the indications were approximately 0.3-inch to 1.1-inch above the tubesheet).

The circumferential indications at the hot-leg, top of tubesheet region were located at the expansion transition.

All indications detected within the tubesheet region were attributed to primary water stress corrosion cracking. The axial indications were small (approximately 0.5-inch). One of the axial indications was located 10.8-inches below the top of the tubesheet. The largest circumferential indication was 3.67 volts, 64-degrees in circumferential extent, and located 8.39-inch below the top of the tubesheet.

The acronym “NSY” stands for noisy. The acronyms “NTE” and “PTE” stand for “no tube expansion” and “partial tube expansion,” respectively.

The volumetric indications on the hot- and cold-leg side of the steam generators were located in high-flow regions and attributed to transient loose parts (i.e., they are not believed to be a result of corrosion).

The largest wear indication in steam generator 1 measured 46-percent through-wall. The largest wear indication in steam generator 2 measured 48-percent through-wall.

No primary water or outside diameter stress corrosion cracking has been found in dents and dings at Waterford 3.

Only 1 free span crack has been identified at Waterford 3 to-date. This indication was detected in 2003 in a tube adjacent to a stayrod (i.e., a crevice region where sludge and contaminants can accumulate).

Based on the finding that some of the “new wear” indications (based on an initial bobbin coil evaluation) were actually a result of cracks, the NRC staff asked whether all historic wear indications in steam generator 1 had been inspected with a rotating probe to confirm that the indications were actually a result of wear. The licensee agreed to provide this information following the conference call. On May 3, 2005, the licensee confirmed that all historic wear indications identified during RF 13 had been inspected with a rotating probe either during RF 13 or in a prior outage (but after January 2000). That is, subsequent to January 2000, all wear indications have been inspected at least once with a rotating probe. The licensee also indicated that it would be performing an evaluation to show that these tubes (i.e., those with wear scars that were not inspected with a rotating probe this outage) will retain adequate tube integrity until the next tube inspections.

On May 9, 2005, the licensee informed the NRC staff that two diagonal batwing supports in steam generator 2 appeared to be broken. This condition was identified during routine eddy current testing which revealed that the two bat wings were displaced from their nominal locations on the cold leg side of tubes in columns 82, 83, and 84. These batwings were at their nominal locations during the previous inspection. A string of wear scars were observed during the current inspection for tubes in these columns extending out to row 73. These wear scars occurred in the free span of the tube at the nominal axial location of the batwing and, thus, were apparently formed prior to the displacement of the batwings. These wear indications were not observed during the previous inspection. The depth of these wear indications ranged from 7- to 30-percent of the tube wall thickness.

Since only the cold leg side of the affected batwings are out of position, the licensee believes that the cold leg diagonal portion of the batwing broke off from the lower horizontal portion of the batwing at the location of the tack welds connecting these pieces (i.e., the tack welds presumably failed). The hot leg diagonal portion of the batwing and the horizontal piece are not expected to move since the horizontal piece is held in place by a support strip. The cold leg diagonals are believed to have displaced downward about 2-inches until the diagonals contacted the 9th cold leg partial support plate. Eddy current testing appears to confirm the subject diagonals being in contact with the 9th partial support.

The licensee is performing a root cause assessment and is assembling a team of industry experts for an independent review. The licensee observed that the failed batwings are among the longest in the bundle and located in the region with the highest flow velocity. The licensee briefly discussed two possible causal mechanisms for failing the batwings: (1) corrosion of the tack welds which may have been aggravated during prior chemical cleanings (i.e., the steam generators have been chemically cleaned twice with the most recent occurring during the previous refueling outage); and (2) a previously plugged tube along the stay cylinder cavity boundary may have completely worn through allowing the stabilizing cable inside to fret against the batwing.

The licensee’s corrective actions have included:

- All tubes in columns 82, 83, and 84 have been plugged out to row 85 in steam generator 2, since the two affected batwings are between columns 82 and 83 and between columns 83 and 84, respectively. In the affected columns, the first three rows of tubes beyond the previous plugging boundary (about eight rows out from the stay cylinder cavity) and then every second row of tubes in an alternating pattern have been stabilized. In addition, all tubes with batwing-induced wear indications have been stabilized.

- All tubes between columns 70 and 106 had previously been plugged, preventively or otherwise, at least eight rows out from the stay cylinder cavity. The licensee has now boxed this region in with tubes containing sentinel plugs (with a design leak rate of 130 gallons per minute (gpm)) on the cold leg side.

- All tubes bordering the stay cylinder cavity that were not previously plugged and stabilized were plugged during this outage. These tubes were either stabilized or contained sentinel plugs on the cold leg side

The license’s current plan is to visually inspect the batwing-to-wrapper bar welds (which are located on the outside of the tube bundle) with a camera. The licensee will also attempt to inspect the location where the batwings are believed to have failed with a miniature camera. The licensee will update the staff on its failure assessment following completion of these visual inspections.

Apart from root cause, the NRC staff indicated that the extent of condition and corrective actions remain an issue. There is no reason to assume that additional batwings may not fail during subsequent cycles. The evidence from the observed initial failures is that the batwings become active immediately prior to failure, leading to accelerated wear of the adjacent tubes. From a safety standpoint, the licensee seems to be relying on the fact that the wear flaws associated with the two batwing failures to-date were limited to a maximum 30-percent throughwall. The licensee also notes that the broken batwings are too heavy to be lifted by the cross flow, such as to migrate elsewhere as a loose part.

On May 13, 2005, another conference call was held between the NRC staff and representatives of Waterford 3 to discuss the results of their investigations into the broken batwings.

The licensee visually inspected the batwing-to-wrapper bar welds and the location of the batwing failure in steam generator 2 with a video camera. The batwing-to-wrapper bar welds of approximately 40 locations were inspected and the welds were intact with no degradation. The welds selected for these examinations were those that penetrated to the stay cylinder region. Visual inspection of the horizontal portion of the batwings was performed for all batwings in the stay cylinder region (the inspection camera was inserted up the stay cylinder cavity to allow access to the lower portion of the batwing). These inspections identified that only two batwings had failed and that the failure location was at the intersection of the batwing and a slotted bar which holds the lower portion of the batwings in place (the slotted bar is part of the lower batwing assembly which is between the top and bottom horizontal plates). The batwing is notched at this location for insertion into the slotted bar. In other words, the batwing failed in the middle of the horizontal portion of the batwing. The inspection of the lower horizontal plate did not result in the identification of any general corrosion concerns in this region.

The failed batwings are approximately 0.85-inches above the eggcrate support, indicating that the total movement was less than 1-inch. This movement equates to approximately a 2-inch displacement axially along the tubes. There were no wear scars on the tubes at the “new location” of the failed batwings.

Based on the location of the failure, the length of the batwing (i.e., one of the longest), and the flow in this region of the tube bundle, the licensee concluded that the failure mechanism was fatigue. The loads on the batwing in this region are not high enough to cause an overload type failure. The batwing was postulated to twist such that the top of the horizontal portion of the batwing contacted one tube and the bottom portion contacted the tube on the other side of the batwing. The batwing in column 88 is the longest batwing in the steam generator.

With respect to the potential of the batwing-to-wrapper bar weld (a 3/32-inch fillet weld) to fail as a result of the batwing failure, the licensee concluded that the loads on this weld would not significantly increase. This conclusion was based, in part, on the tubes not being perfectly aligned; therefore, the tubes react to any load imposed as a result of the batwing failure. The batwings are expected to move more in the horizontal direction rather than in a vertical direction. The bending stress on the weld was confirmed to be less than the yield strength. The batwing weighs approximately 7 to 8 pounds.

The tubes surrounding the stay cylinder that were stabilized during the outage were stabilized on both the hot- and cold-leg. In addition, they were stabilized to the first vertical strap (i.e., through the bend in the tube). The stabilizers are 0.5-inch in diameter and the tube has an inner diameter of 0.656-inch. It is expected that if the batwings wear a hole through a tube, that any wear from the batwing contacting the stabilizer will result in similar wear rates of the two surfaces.

Similar failures have not been observed in other plants with Combustion Engineering-type steam generators, despite having longer run times than Waterford 3, and having performed chemical cleaning.

In assessing future wear rates at the location of the failed batwings, the licensee increased the highest work rate ever observed by a factor of two, and concluded that adequate tube integrity would be maintained until the next tube inspections.

The scope and rationale for the plugging and stabilization performed during the outage was based on engineering judgment. In rows 82, 83, and 84, the failed batwings are supported by the ninth eggcrate. As a result, the plugging and stabilization went out to the ninth eggcrate. In addition, since less vibration is expected further into the tube bundle, the licensee plugged tubes and plugged and stabilized other tubes in an alternating pattern. The licensee also assessed the potential for the batwing to affect the ninth eggcrate support and the tubes supported by the ninth eggcrate, and concluded that this was an acceptable condition (i.e., for the batwing to rest on the ninth eggcrate). The failed batwings are actually resting on the scallop bar which forms the front face of partial eggcrate 09C.

Following the May 13, 2005, conference call, the NRC was informed that a visual inspection was performed of the batwings in steam generator 1. These inspections did not reveal any broken batwings; however, two or three appeared to be slightly twisted about their vertical axis.

On May 25, 2005, the NRC staff held another conference call with representatives of Waterford 3 to discuss their assessments in further detail. During the call, the licensee indicated that the root cause report (or more precisely, the apparent cause report) was still being finalized. The licensee has not determined what caused the fatigue failure; however, they believe they have bounded the condition by the plugging, stabilization, and analyses that they performed during the outage.

For areas outside the stay cylinder region, fatigue failure is not likely since the displacements in this region are limited, the length of the batwings are shorter, and the flows are lower. In addition, there are no general corrosion concerns and there are no chemical cleaning corrosion concerns (based on the visual inspections performed during the outage).

The licensee evaluated the integrity of the batwing-to-wrapper bar weld. The licensee concluded that there are no significant forces that will lift the batwing (in an up and down motion) so as to work the weld; however, they did not consider the potential for the horizontal portion of the batwing to rotate (presenting a larger area for the vertical flow to act upon) and then evaluate the lifting motion of the batwing. There was no visual evidence that the broken batwings were twisted. The licensee evaluated a 2-inch movement of the batwing and concluded that the stresses on the weld from the 2-inch drop were below the weld endurance limit. In addition, they considered the cyclic stresses associated with moving the batwing up and down by 2-inches and concluded that this was within the fatigue limits. A 2-inch motion was selected since the partial eggcrate limits the downward motion of the batwing and the top horizontal plate (of the lower batwing assembly) limits the upward motion of the batwing.

The licensee indicated that the failure was a "type 3" fatigue type failure and that it may have been exacerbated by the chemical cleaning. The "root cause" analysis was expected to be completed later in the week.

The staff did not identify any issues that would warrant preventing the plant from starting up. The staff asked the licensee to provide a copy of the operational assessment and the root cause report.

Waterford Steam Electric Station, Unit 3
cc:

Mr. Michael E. Henry, State Liaison Officer
Department of Environmental Quality
Permits Division
P.O. Box 4313
Baton Rouge, Louisiana 70821-4313

Vice President Operations Support
Entergy Operations, Inc.
P. O. Box 31995
Jackson, MS 39286-1995

Director
Nuclear Safety Assurance
Entergy Operations, Inc.
17265 River Road
Killona, LA 70066-0751

Wise, Carter, Child & Caraway
P. O. Box 651
Jackson, MS 39205

General Manager Plant Operations
Waterford 3 SES
Entergy Operations, Inc.
17265 River Road
Killona, LA 70066-0751

Licensing Manager
Entergy Operations, Inc.
17265 River Road
Killona, LA 70066-0751

Winston & Strawn
1700 K Street, N.W.
Washington, DC 20006-3817

Resident Inspector/Waterford NPS
P. O. Box 822
Killona, LA 70066-0751

Regional Administrator, Region IV
U.S. Nuclear Regulatory Commission
611 Ryan Plaza Drive, Suite 400
Arlington, TX 76011

Parish President Council
St. Charles Parish
P. O. Box 302
Hahnville, LA 70057

Executive Vice President
& Chief Operating Officer
Entergy Operations, Inc.
P. O. Box 31995
Jackson, MS 39286-1995

Chairman
Louisiana Public Services Commission
P. O. Box 91154
Baton Rouge, LA 70825-1697