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1CAN041305

April 30, 2013

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

Subject: Response to Request for Additional Information
Related to Fall 2011 Steam Generator Tube Inservice Inspections
Arkansas Nuclear One - Unit 1
Docket No. 50-313
License No. DPR-51

References:
1. Entergy letter dated March 22, 2012, "Steam Generator Tube Inspection Report – 1R23" (1CAN031203) (ML12086A294)
2. NRC email dated March 11, 2013, "Request for Additional Information – TAC No. ME8279" (ML13070A289)

Dear Sir or Madam:

Entergy Operations, Inc. submitted information summarizing the results of the Fall 2011 steam generator tube inspections performed at Arkansas Nuclear One, Unit 1 (Reference 1). On reviewing the submittal, the NRC staff requested additional information to continue the review and issued Reference 2. The response to the Reference 2 request is attached.

This submittal contains no regulatory commitments.

Should you have any questions, please contact me.

Sincerely,

SLP/rwc

Attachment: Response to Request for Additional Information Regarding the Steam Generator Tube Inservice Inspection Fall 2011 Refueling Outage

A047
NRR

cc: Mr. Arthur T. Howell
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**Attachment To**

**1CAN041305**

**Response to Request for Additional Information**
**Regarding the Steam Generator Tube Inservice Inspection**
**Fall 2011 Refueling Outage**

REQUEST FOR ADDITIONAL INFORMATION REGARDING

THE STEAM GENERATOR TUBE INSERVICE INSPECTIONS FOR THE FALL 2011 REFUELING OUTAGE

TAC NO. ME8279

DOCKET No. 50-313

By letter dated March, 22, 2012, (Agencywide Documents Access and Management Systems Accession Number [ADAMS] ML12086A294), Entergy Operations, Inc., the licensee, submitted information summarizing the results of the fall 2011 steam generator (SG) tube inspections performed at Arkansas Nuclear One, Unit 1. The licensee discussed the progress and initial findings of the outage with the U.S. Nuclear Regulatory Commission (NRC) staff in a teleconference summarized in a memorandum dated October 12, 2012 (ADAMS Accession Number ML12276A301). The licensee participated in a category 1 public meeting on January 26, 2012 to discuss tube-to-tube wear indications observed during the outage. The meeting summary can be found in ADAMS under Accession Number ML120270400.

In order for the staff to complete its review of the fall 2011 SG tube inspections, please provide the following:

1. **For the last several inspection outages, please provide the effective full power years that the SGs had operated at the time of the inspection.**

| Year | End of Cycle Outage Designation | Actual SG Operating Cycle Length (EFPM) | Actual SG Operating Cumulative Cycle Length (EFPM) | Actual SG Operating Cycle Length (EFPY) | Comment |
|---|---|---|---|---|---|
| 2005 | 1R19 | 0 | 0 | 0 | Baseline |
| 2007 | 1R20 | 15.74 | 15.74 | 1.31 | 1st ISI |
| 2008 | 1R21 | 16.83 | 32.56 | 1.40 | 2nd ISI |
| 2010 | 1R22 | 14.80 | 47.36 | 1.23 | 3rd ISI |
| 2011 | 1R23 | 17.15 | 64.51 | 1.43 | 4th ISI |
| 2013 | 1R24 | 15.87 | 80.38 | 1.32 | 5th ISI |

2. **The tube in row 43, column 8 could not be stabilized. Please discuss the reason that the tube could not be stabilized. If it was because of bowing, please discuss if it would be expected that the tube could not be stabilized given the measured extent of bowing (given the size/stiffness of the stabilizing cable).**

The most likely reason for inability to stabilize the tube in R43 C8 was the combination of bowing and the uniquely designed stabilizer for the 1R23 outage.

The qualified stabilizer for Arkansas Nuclear One, Unit 1 (ANO-1) is a heat treated cable with segments of rigid sleeves. During 1R23, two attempts were made to install a segmented stabilizer at the location R43 C8. After the first attempt, a review of the condition was made and based on judgment it was assumed that the stabilizer could have kinked during installation. During the second attempt the second stabilizer was inserted to the same depth. With the same resulting relative insertion indicating the stabilizer was binding at the same location. Entergy expected to be able to install the qualified stabilizer in this tube; however, based on the extent of bowing of the tube during cold conditions and the length of the rigid sleeve, the stabilizer could not pass. The non-insertion condition was entered into Entergy's Corrective Action Program as CR-ANO-1-2011-02146.

3. **The bowing in the upper spans of SG B appears to be larger than for SG A. In SG B, one tube was plugged for bowing in the upper portion of the SG (upon initial discovery of this phenomenon).**

   a. **Please discuss if this experience is similar to what has been observed in SG A. If the experience is different, please discuss any insights on the nature of the difference.**

      This is similar to what is observed in SG A. The bowing is a function of which tube support plates (TSP) hang on the inner shroud and which side of the support plate are affected also. For example if the top TSP hangs on the "z" side of the generator and the TSP below it hangs in a slightly different spot, the effect on the upper spans results in an "S" shape bow due to the plates moving in slightly different directions. Additionally the extent of the bowing is also affected by when the TSP actually hangs on the inner shroud during the cool down. The extent of the bowing in the upper span is therefore a function of which TSPs lock, where and when.

   b. **Please discuss any insights on why the tie rod bowing in SG B manifested itself after several cycles of operation (i.e., what changed in the steam generator that would cause the tube supports to "lock up" after several cycles of operation).**

      Because SG B possessed no detectable bowing after the first three operating cycles (1R20, 1R21, 1R22) but did after the fourth operating cycle (1R23), it is postulated that the change in the condition of the surfaces increased the effective friction coefficient and resulted in some previously 'partially bound' locations (1R20, 1R21, 1R22) on certain TSPs to become 'fully bound' (or at least significantly more bound; 1R23). This increased binding results in larger vertical pull-down forces during plant cool down and the consequent increased tie rod bowing.

      Based on the many similarities shared by SG A and SG B, the same basic mechanism (frictional binding) that is occurring in SG A is now detectably active in

SG B. The presence of a common active mechanism producing tie rod bowing in SG A and SG B is somewhat anticipated. This is because the mechanism involves several effects occurring during fabrication and both steam generators were fabricated using the same materials, tools, techniques, procedures and processes.

The regions experiencing frictional binding have interferences that are a result of fabrication tolerance stack-up. Potentially, the difference between 'binding' and 'no binding' could be only a few mils of interference or clearance. It is postulated that the local regions of tolerance stack-up result in more interference for SG A as compared to SG B. Hence, for SG B the cumulative surface corrosion and/or small particulate accumulation over a longer time (3 refuel cycles) was required to offset the initial clearance (or increase initial low level binding) and produce sufficient binding to create tie rod bowing.

4. **In Section 3.7 of your report, you indicate that there were five new tube-to-tube proximity indications. In Table 3.7.1, there appears to only be three new tube-to-tube proximity indications (outermost ring in 14$^{th}$ (row 128) and 15$^{th}$ (row 12) span; third outermost ring in 1$^{st}$ span (row 85)). Similarly, for SG B, it was indicated that there were seven locations of tie-rod-to-tube contact, but the table only appears to list six locations (also, for SG A, 11 locations in text and 9 locations in Table for 1R20). Please clarify.**

   Table 3.7.1 and 3.7.2 were an attempt to present the extent of bowing for a given location. This is broken down by span and ring and row for a particular tie rod. For example the row 12 listed in the 15$^{th}$ span also has a row 13 in the 15$^{th}$ span that is associated with the same tie rod. Therefore the reference to five new proximity indications is related to the number of tubes not locations. There are 92 tubes with some form of proximity currently in SG A for 1R23. That can be a tie rod to a tube, a tube to a tube or both.

   For SG A - Five new tube-to-tie rod proximity indications were detected, one in the first span, two in the fourteenth span, and two in the fifteenth span.

   | Row | Tube | Span |
   |---|---|---|
   | 13 | 18 | 15 |
   | 24 | 10 | 15 |
   | 110 | 8 | 14 |
   | 128 | 10 | 14 |
   | 85 | 36 | 1 |

   Tie rods change slightly from outage to outage but historically have bowed in the same general direction. The magnitude of bowing can also change in either direction. For example it can increase but can also stay the same or decrease if the load is directed towards the inner rings more than the outer ring.

   The number for SG B that was referenced in the report was seven tubes that were in contact with tie rods in the first span and not tie rod locations.

Any tube coming in contact with a tie rod at power will be removed from service by plugging. This will account for a projected residual bow.

5. **Please discuss any insights on the nature of the new pattern of "appreciable" wear at tube support plate 6 in SG A.**

   a. **Is there any correlation of this wear with the tie rod bowing issue (even in light of the fact that the bowing occurs during shutdown periods)?**

      No – the TSP wear appears to be a function of the tube pre-load which is under investigation as part of the tube to tube wear (TTW) root cause. The tubes around the tie rods do not have consistent wear at the TSPs.

   b. **Has anything occurred operationally (e.g., power uprate, significant change in SG operating parameters (e.g., feedwater temperature)) that would explain the significant increase in the number of new wear indications at the tube support plates?**

      No – all operating parameters have remained the same since the steam generators were replaced in 2005.

   c. **Has the number of new wear indications increased or decreased (per outage) since SG replacement?**

      Even the original steam generators would periodically see changes in the number of new indications. This would appear to be consistent.

| Outage | SG A Wear Calls | SG A New Wear Calls | SG B Wear Calls | SG B New Wear Calls |
|---|---|---|---|---|
| 1R20 | 690 | 690 | 512 | 512 |
| 1R21 | % 990 | 524 | % 1029 | 685 |
| 1R22 | * | * | * | * |
| 1R23 | 1492 | # 501/2 = 251 | 1414 | # 396/2 = 198 |

* Only Tie Rods Were Inspected

\# This value is for 2 fuel cycles so it is divided by 2

% During the first inservice inspection (ISI) (1R20), only a sample of the total wear population was re-inspected (using X-Probe) for confirmation. During 1R21 however, every wear indication was re-inspected. The 1R21 re-inspection resulted in approximately one-third of the 1R20 wear calls being re-classified as

"NDF" (no defect found). Even though these indications have been re-classified, the "TWD" (through-wall degradation) call stored in the Data Management System for the 1R20 outage still remains as the official 1R20 call. The update to "NDF" is reflected in the 1R21 data.

SG-A: 690 (1R20 TWDs) – 466 (1R21 repeats) = 224 (1R21 NDFs)
SG-B: 512 (1R20 TWDs) – 344 (1R21 repeats) = 168 (1R21 NDFs)

**d. Has the growth rate of the wear indications increased or decreased with time?**

The repeat and new growth rates have continued to decrease with time. The once-through design results in different parts of the generator having different wear rates. For example in the 9th span where the aspirating ports are, the cross flow becomes more turbulent which results in higher rates than the lower part of the bundle.

| Outage | SG A Repeat Growth Rate (%/EFPY) | SG A New Growth Rate (%/EFPY) | SG B Repeat Growth Rate (%/EFPY) | SG B Repeat Growth Rate (%/EFPY) |
|---|---|---|---|---|
| 1R20 | 1st ISI | 9.3 | 1st ISI | 11.4 |
| 1R21 | 3.57 | 8.56 | 5.71 | 9.99 |
| 1R22 | * | * | * | * |
| 1R23 | 1.87 | 5.3 | 2.62 | 6.4 |

* Only Tie Rods Were Inspected

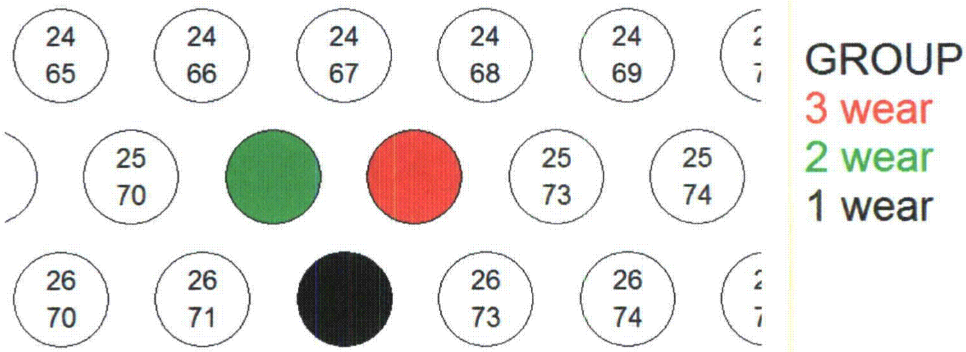
**6. One tube had three indications of wear attributed to tube-to-tube contact. In order for this to occur, the tubes involved would have to move in different directions to affect the tube in the middle.**

The 1R23 Condition Monitoring Operational Assessment (CMOA) (AREVA document 51-9173653-002) identified two locations with three wear scars, both in SG B (21-47 and 25-72). Note that this identification was made after re-analysis was performed on prior inspection data from 1R20 and 1R21 as well 1R23 based on limited number of tubes with Array or +Point data.

The initial planned 1R24 SG B eddy current inspections are complete. Inspections using qualified array techniques have identified one tube with TTW indications. The tube SG B R25 T72 has 3 wear scars and is shown below. The 1R24 inspections were performed for tie rod bowing phenomena. These inspections included tubes with previous TTW indications but not adjacent tubing. Adjacent tubing to R25 T72 could have TTW and currently would remain uninspected.

Additional testing is planned for 1R24 to support diagnostic testing of tubing preload. This testing is referred to as Frequency Response Testing. It includes pre- and post-test eddy current.

Testing of adjacent tubing to R25 T72 will be performed with the Array Probe.




**SG B Location of Tube with 3 Wear Scars**

**a. Is this information being considered in your root cause assessment?**

For the TTW Root Cause Analysis (RCA), the fact that a tube can be in contact with one or more tubes and experiencing wear is not an unlikely event. In this case, tube R25-T72 may not be active in the bowing, but rather affected by its neighbors bowing towards it. The additional inspection mentioned above will help in this determination.

The Tie Rod Bowing RCA does not consider TTW as a possible cause for tie rod bowing.

**b. Has the extent of movement of the tubes been considered in evaluating the inspection findings (assume that the affected tube moved in one direction then a neighboring tube would have to move considerably more to come into contact with the "affected" tube – is there any concern with the extent of movement on tube integrity)?**

Extent of movement is not necessary in evaluating of the inspection findings when considering tie rod bowing, as bowing is due to compressive load caused by controlled movement of the tube sheets. Moreover, the measurements for tubes bowings during inspection only found one or two tubes with bowing, which suggest that tubes restored their "straight" condition after the loads were released.

In regards to evaluation of the TTW itself, the extent of movement is not a contributing factor for determining structural integrity for evaluation of CMOA.