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May 31, 2007

U.S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D.C. 20555

Subject: Duke Power Company LLC d/b/a Duke Energy Carolinas, LLC (Duke)
Catawba Nuclear Station, Unit 2
Docket Number 50-414
Reply to Request for Additional Information Concerning Steam Generator Outage Summary Reports for End of Cycle 14 and for End of Cycle 13 Refueling Outages (TAC Number MD3419)

Reference: Memorandum from Allen L. Hiser, Jr. to Evangelos C. Marinos, dated February 20, 2007 (communicated to Duke via electronic mail dated March 6, 2007)

Please find attached Catawba's reply to the referenced Request for Additional Information (RAI). The RAI was received on March 6, 2007 via electronic mail. The format of the attachment is to restate each RAI question, followed by our reply.

There are no regulatory commitments contained in this letter or its attachment.

If you have any questions concerning this material, please call L.J. Rudy at (803) 831-3084.

Very truly yours,

James R. Morris

James R. Morris

LJR/s

Attachment

A001
NRC/NRR

xc (with attachment):

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ATTACHMENT

REPLY TO NRC REQUEST FOR ADDITIONAL INFORMATION

REQUEST FOR ADDITIONAL INFORMATION
STEAM GENERATOR OUTAGE SUMMARY REPORT FOR END OF CYCLE 13
AND 14 REFUELING OUTAGES
CATAWBA NUCLEAR STATION, UNIT 2
DOCKET NUMBER 50-414

1. A review of historical documentation available for Catawba Unit 2 and model D5 steam generators identified an apparent discrepancy in the number of tubes in each steam generator. Please confirm the number of tubes in your steam generators is 4578 which includes 8 thimble (stub) tubes that are plugged.

   It was also observed in this historical document review that there is a discrepancy between your reports submitted for the end of cycle (EOC) 12 refueling outage in 2003. Your letter dated April 7, 2003 (page 3 of 217), indicates that tube 2D R49C56 was plugged. However, your letter dated June 18, 2003 (page 133 of 346), does not indicate that this tube was plugged. Please confirm that tube 2D R49 C56 was plugged during the EOC 12 outage.

Duke Response:

There are 4578 tube holes in each of the Catawba Unit 2 steam generators which include 8 thimble (stub) tubes that are plugged.

Tube 2D R49 C56 was plugged during the EOC 12 outage.

2. Please provide the cumulative effective full power months for each of your steam generator tube inspections.

Duke Response:

End of Cycle	Refueling Outage Date	Per Cycle Effective Full Power Months (EFPM)	Cumulative EFPM Including First Cycle	Cumulative EFPM Excluding First Cycle	Periods
1	2/1988	11.04	11.04		
2	2/1989	9.36	20.4	9.36	First Period
3	6/1990	10.80	31.2	20.16	First Period
4	10/1991	11.40	42.6	31.56	First Period
5	1/1993	12.24	54.84	43.8	First Period
6	5/1994	12.48	67.32	56.28	First Period
7	10/1995	14.04	81.36	70.32	First Period
8	3/1997	14.40	95.76	84.72	First Period
9	9/1998	15.72	111.48	100.44	First Period
10	3/2000	14.76	126.24	115.2	First Period
11	9/2001	16.80	143.04	132	Second Period
12	3/2003	15.72	158.76	147.72	Second Period
13	9/2004	17.40	176.16	165.12	Second Period
14	4/2006	16.56	192.72	181.68	Second Period

3. Please describe the scope and results of any secondary side inspections performed during the EOC 14 refueling outage.

Duke Response:

Secondary side inspections were performed during the EOC 14 outage in all four steam generators on the pre-heater baffle plate (18C).

At the pre-heater baffle plate there were 22 objects identified with 11 removed in the A steam generator, 76

objects identified with 57 removed in the B steam generator, 76 objects identified with 50 removed in the C steam generator, and 28 objects identified with 15 removed in the D steam generator. There were a total of 202 objects identified with 133 removed. All of the objects not removed were evaluated for acceptability to leave in place for one cycle of operation.

In addition, the pre-heater waterboxes were inspected with special emphasis on the waterbox cap plate. These inspections were completed as a follow-up to these same inspections performed during the EOC 13 outage. Components inspected were the rib assembles, impingement plate, and cap plate. Only steam generators 2B, 2C, and 2D were inspected, as steam generator 2A had been verified to have no cap plate cut out during the EOC 13 inspections.

4. Please discuss the primary to secondary leak rate observed during the cycle preceding the EOC 14 refueling outage. Has there been any appreciable change since implementation of the tubesheet alternate repair criteria?

Duke Response:

No detectable primary to secondary leakage occurred during cycle 14. No detectable primary to secondary leakage has occurred during cycle 15 to date.

5. Recent Operating Experience at another plant with Westinghouse model D-5 steam generators identified degradation of the water box cap plate in the preheater region in 2004 and unexpected wear/erosion in the primary moisture separator region on 12 of the 16 primary separator assemblies in 2005 (ADAMS Accession Nos. ML042260202 and ML062560349, respectively). Please discuss whether you have inspected these regions of the steam generator during your secondary side inspections in the past. If so, discuss when the inspections were performed and the results. Discuss what plans, if any, you have on inspecting these regions in the future.

Duke Response:

The pre-heater water box was inspected during both the EOC 13 and EOC 14 outages. Steam generator 2A had been verified to have no cap plate cut out during inspections at EOC13.

The focus of the waterbox inspection was to evaluate modifications to the cap plate during manufacturing. The cap plate had two sections cut out and welded back in place. Industry experience necessitated an inspection to assess the condition of the welds holding these plates in place. Catawba Unit 2 has this type cap plate cut out in the 2B, 2C, and 2D steam generators. Inspections during EOC 13 found these welds to be structurally sound and the follow-up inspections during EOC 14 found no change in the conditions.

An inspection of the primary moisture separator region of the steam generator was last performed during the EOC 8 outage (1997) in the 2C steam generator. No evidence of wear or erosion was identified during the inspection. Moisture separator wear/erosion inspections are planned for two steam generators during the Catawba Unit 2 EOC 15 outage in 2007. This is not a commitment.

6. During your EOC 13 and EOC 14 steam generator tube inspections several possible loose part (PLP) indications were detected. Some of these indications were in the periphery of the tube bundle while some were in the interior. These PLPs were reported at the top of the tubesheet and at tube support plates. In addition, it appears that some of the loose parts were only identified visually (i.e., without a corresponding eddy current indication of a loose part). Please discuss the source of these loose parts and PLPs. In addition, discuss any corrective action taken in response to observing these loose parts. If any loose parts were left in the steam generators, please discuss whether an assessment was performed to confirm tube integrity would be maintained with these loose parts in the steam generator.

Duke Response:

There are two basic sources of the foreign objects in the steam generators. The sources are parts from original fabrication/construction of the steam generators and parts introduced into the steam generators from the secondary system. The foreign objects from the secondary plant systems includes material from failure of components (e.g., valves, gaskets), material from degradation of the secondary system (e.g., sludge/sludge rocks), and materials from construction and maintenance of secondary plant systems (e.g., weld slag, backing bars). The use of proper gasket types and emphasis on foreign material exclusion awareness

while working on secondary side systems has been addressed in the Catawba corrective action program.

For loose parts that are identified by visual inspection, the first option is to retrieve the object. If the part cannot be retrieved, then information is gathered about the size, shape, material, location, amount of sludge, and how fixed the part is in its position. This information is needed in order to perform a formal engineering analysis to leave the object in place. In addition, eddy current is performed to look for any degradation associated with those parts. A formal assessment was performed for all loose parts identified by visual inspection during EOC 14 that were not retrieved to confirm that tube integrity would be maintained.

Possible loose parts (PLP) are also independently identified by eddy current. Most PLP indications are identified with the array and/or rotating coils. These indications are not always loose parts, but can be sludge rocks or localized sludge deposits. PLPs are usually bounded to the extent necessary to determine if additional PLPs or degradation is present. The practice is to bound indications until no more PLPs or degradation is reported. All PLPs are assessed to determine if a visual inspection and retrieval is possible. The most severe condition is PLPs identified with degradation present. Tubes with this condition are removed from service.

For other PLP indications where no degradation is present and visual inspection and retrieval are not performed, a subjective assessment is performed based on engineering judgment to determine if repair is necessary. The subjective assessment considers location, quantity and type of indication, and previous history. Integrity assessments are not performed for PLP indications by eddy current when degradation is not present. A formal engineering analysis is not performed because it is difficult to estimate the mass, shape, and material from eddy current to assume in an analysis.

7. For both EOC 13 and EOC 14 refueling outages, discuss the results of the eddy current and visual inspections of the tube plugs.

Duke Response:

All tube plugs were visually inspected. Also, 20% of the plugs were inspected with rotating pancake coil. No anomalies were reported for the inspections of these plugs.

8. Following the discovery of several crack-like indications in your EOC 13 outage, the Nuclear Regulatory Commission (NRC) staff obtained the eddy current data for 16 tubes with these crack-like indications. The eddy current data were reviewed by an NRC contractor. The review identified differences in the measured signal amplitude and phase that can lead to different estimates of flaw size and extent. These differences could have been a result of the variability in the calibration setup (between the staff's contractor and your analysts) or due to improper selection of the maximum signal. Several examples of this variability were in the indications reported in tubes R4C61, R13C64, and R2C57. For these indications, the NRC estimated the maximum amplitude of the signals as 1.24 volts, 4.3 volts, and 1.85 volts, respectively. In addition to the differences in signal amplitude and phase, the NRC review also identified differences in the number and orientation of indications since it appears that only one of the indications may have been reported for each tube section. For example, in the tube in R13C64, two single axial indications were identified by the staff but only one appears to have been reported. Please confirm that you may not have reported all indications in a tube (i.e., that once you identified one indication, additional indications may not have been identified and reported).

Duke Response:

Without additional information, i.e., data point location, coil used to measure indication(s), etc., Duke cannot assess the differences in signal amplitude and phase for the three tubes cited in the question. This situation could be explained by variability in the calibration setup or different selection of the maximum signal as described in the RAI.

This RAI did not identify the steam generator for tube R13 C64, but after investigation, the steam generator was determined to be the 2B steam generator. By letter dated January 17, 2005, the results for tube R13 C64 were reported as containing an SAI and a PID.

The site-specific analysis guidelines in place for that outage required reporting of all indications. However, as for the individual case of tube R13 C64, only one indication was detected and reported. There is a finite probability of detecting any particular indication. The tube was plugged based on the single indication.

9. You mention in the EOC 14 report that the tubesheet region was randomly sampled with an array probe. Did the random sample include the cold leg side, (e.g., on the periphery to locate PLPs) or was just the hot leg side inspected?

Duke Response:

The random sample of the tubesheet only included the hot leg. As a correction to information previously submitted, the periphery tubes were inspected using a combination bobbin and array probe. However, only the bobbin data was analyzed for degradation, while the array data was only analyzed based on bobbin results (i.e., for special interest locations). The incorrect reporting in Duke's previous correspondence was entered into the Catawba corrective action program.

10. Were any non-expanded or partially-expanded tubes on the hot-leg or cold-leg side of the steam generator left in service? If so, discuss the scope and results of the inspections performed on these tubes (in the tubesheet region) during the EOC 14 outage. Were any tubes that were over-rolled at the top of the tubesheet (i.e., the expansion transition is above the top of the tubesheet) left in service? If so, discuss the scope and results of the inspections performed on these tubes during the EOC 14 outage. Please clarify the difference between a tube with an "over-roll condition at the top of tubesheet" and a tube with "expansion geometry at top of tubesheet."

Duke Response:

There were no known non-expanded or partially-expanded tubes on the hot leg or the cold leg side of the steam generator left in service.

Some tubes were left in service with slight over-rolls. Slight over-rolled conditions outside the tubesheet are

believed to be acceptable. There are 13 over-roll conditions reported in historical data. The three tubes removed from service during EOC 14 had over-rolls that were significantly outside the tubesheet (> 1.75 inches). There are 10 tubes remaining with over-rolls that are less than one inch outside the tubesheet. One tube was not inspected during the EOC 14 outage. The remaining inspected tubes contained no degradation.

An over-roll condition is where a tube has been expanded above the top of the tubesheet. The expansion geometry as described is where a specific expansion has been reported as an indication by one technique and subsequently inspected using other qualified probe techniques. Information from the additional techniques found the indication to be not degraded, but related to tube geometry based on comparison to historical data.

The one tube that was not inspected during the EOC 14 outage was removed from service to save the resources needed to disposition this tube every outage.

11. Please clarify the following sentence from page 7 of 22 of your August 31, 2006 letter: "OA [Operational Assessment] issues include a small population of tubes which were last inspected at EOC 11 and will not be inspected again until EOC 15 and growth of the wear scars left in service at EOC 14." In addition, with the information provided in response to question 2 above, please show that the inspection sampling requirements in TS 5.5.9 for these tubes were met.

Duke Response:

The longest remaining operating interval prior to a future inspection is for a small population of tubes (20%) that were last inspected at EOC 11 and found to have no detectable degradation, but will not be inspected again until EOC 15, which equates to a projected inspection interval of 5.54 EFPY. The largest NDE depth found at EOC 14 but not detected during the 100% inspection at EOC 10 is 31% through wall (TW). This is the largest wear scar that developed from a previously undetected population over the last 5.54 EFPY of operation. It is a reliable projection of the largest expected wear scar at EOC 15 from the population of tubes found to be NDD at EOC 11. Since the condition monitoring limit is 63% TW, both condition monitoring and

operational assessment structural integrity are projected for the population of previously undetected scars with the largest inspection interval.

From an operational assessment standpoint, growth of wear scars detected and left in service at EOC 14 will lead to the largest projected wear scar depth at EOC 15. The projected EOC 15 worst case depth from this population is substantially less than the structural allowable depth. Therefore, operational assessment structural integrity is demonstrated.

A 100% inspection was performed by bobbin at EOC 10 with a cumulative 115.2 EFPM of operation at the end of the first period (120 EFPM period after the first cycle as required by Technical Specifications). Greater than 50% of the tubes were inspected by the midpoint of the second period of 90 EFPM. The half-way point occurred at EOC 13 with 165.12 EFPM. The half-way point of the second period was 165 EFPM. The Technical Specification sampling requirements have been met.

12. It was noted that tubes surrounding plugged tubes were inspected. Please discuss the reason for these inspections (i.e., what is the degradation mechanism or possible degradation mechanism that could be affecting the surrounding tubes).

Duke Response:

Operating experience has indicated that it is a good practice to inspect around plugged tubes to look for tube wear from rupture lips of adjacent tubes or severed tubes. In addition, where tubes have been repaired for loose part wear, it is a good practice to look at the adjacent tubes for additional evidence of loose parts.

13. Several tubes were listed in the EOC 14 report with wear indications and no through-wall depths were provided for these indications (e.g., steam generator C, row 48, column 48 and steam generator D row 42 column 64). Please discuss why these indications were not sized (or alternatively provide the size of these indications). If these indications could not be sized, please discuss how these indications were evaluated relative to the tube repair limit.

Duke Response:

These particular indications were not sized during the outage. They were not sized because they were dispositioned by qualified personnel and determined to meet structural limits.