Progress Energy

Crystal River Nuclear Plant
Docket No. 50-302
Operating License No. DPR-72

Ref: 10 CFR 50.90

November 24, 2004
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U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555-0001

Subject: Crystal River Unit 3 – Response to NRC Request for Additional Information Regarding Once-Through Steam Generator, Special Reports 03-01 and 04-01

Reference: Request for Additional Information Regarding the Crystal River Unit 3 – Special Report 03-01: Once-Through Steam Generator Notifications Required Prior to MODE 4, and Special Report 04-01: Results of the Once-Through Steam Generator Tube Inservice Inspection Conducted During Refueling Outage 13 (TAC NO. MC1853)

Dear Sir:

Florida Power Corporation, doing business as Progress Energy Florida, Inc. (PEF), is providing in the Attachment to this letter, the Crystal River Unit 3 (CR3) response to the referenced Request for Additional Information.

This letter establishes no new regulatory commitments.

If you have any questions regarding this submittal, please contact Mr. Sid Powell, Supervisor, Licensing and Regulatory Programs at (352) 563-4883.

Sincerely,

Michael J. Annacone
Manager Engineering

MJA/lvc

Attachment:

Response to NRC Request for Additional Information (RAI) Regarding Once-Through Steam Generator Tube Inspection Reports 03-01 and 04-01

xc: NRR Project Manager
Regional Administrator, Region II
Senior Resident Inspector

A001

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FLORIDA POWER CORPORATION

CRYSTAL RIVER UNIT 3

DOCKET NUMBER 50-302 / LICENSE NUMBER DPR-72

ATTACHMENT

RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION (RAI) REGARDING ONCE-THROUGH STEAM GENERATOR TUBE INSPECTION SPECIAL REPORTS 03-01 AND 04-01

RAI Question 1

The calculated amount of leakage during postulated accident limits exceeded expectations and the leakage limit. A root cause analysis determined the cause for exceeding the as-found leakage limit was that the use of the probability of detection for tube end cracking does not provide sufficient margin to account for the increase in the number of tube end cracks in future outages. Given the root cause, please discuss how this affects your current projections for accident-induced leakage during the current operating cycle (as discussed in the original request for additional information). That is, address whether adequate leakage integrity will be maintained once the initiation of new indications are included in the existing leakage model. If adequate leakage integrity will not be maintained, discuss your proposed corrective action.

Response

When the postulated Steam Line Break (SLB) as-found primary-to-secondary leakage was determined to be greater than the leakage limit, it was recognized that the probability of detection (POD) was adequate to account for a small number of previously undetected Tube End Cracks (TEC), but was not sufficient to compensate for the larger number of tubes with new TEC indications. This information was not recognized during the previous Refueling Outage (12R). However, since this was recognized during 13R, CR3 was able to perform an expanded re-roll repair effort which reduced the effective number of tubes with TEC, and associated leakage, for those remaining in service. The as-left number of tubes with TEC was reduced to a low level where the resulting as-left leakage, combined with the projected new TEC leakage, and an additional POD margin will be less than the CR3 leakage limit. Projections for the next Refueling Outage (14R) show that both Once-Through Steam Generators (OTSGs) will meet the leakage integrity criteria even with additional new TEC indications.

RAI Question 2

With respect to the number and extent of tubes inspected, please address the following:

a. Please clarify the number of tubes in the "kidney region."

b. Please clarify the number of sleeves currently installed (and in service) in the steam generators. Please clarify whether all sleeves are installed in the lane/wedge region or whether they are installed in other regions of the tube bundle.

c. Thirty-four percent of the dents greater than 2 volts were inspected with a rotating probe. Please discuss whether the voltage calibration at Crystal River is consistent with standard industry practice. If not, please clarify your calibration procedure to permit a comparison of the voltage readings at your plant to other plants.

d. Please clarify what bobbin indications were further characterized with a rotating probe. For example, were all suspect wear locations inspected with a rotating probe to confirm the absence of cracking? If not, please address the technical basis for the criteria used to disposition potential wear locations.

e. Please clarify why the number of tubes examined with the bobbin coil does not equal the number of tube ends examined with a rotating probe. For example, Table 1 indicates that 15,151 upper tube ends were examined with a rotating probe in steam generator A, but 15,314 tubes were examined with a bobbin coil. Were the upper tube ends for approximately 150 tubes not examined? If not, why not?

f. Please clarify the scope and extent of any rotating probe inspections performed at re-roll locations in your steam generators.

Response

a. For 13R, the population of the kidney region was 6,041 tubes in the "A" Once-Through Steam Generator (A-OTSG) and 4,080 in the B-OTSG.

b. Originally, there were 163 Alloy 690 sleeves installed in each OTSG upper tubesheet lane/wedge region. No sleeves are installed in other areas of the steam generators. Currently, there are 159 sleeved tubes in-service in A-OTSG and 156 tubes in-service in B-OTSG.

c. The bobbin voltage is normalized to 4.0 volts using the 4-20% through-wall holes. For the rotating coil examination, voltage is normalized using the 100% Circumferential Electro Discharge Machining (EDM) Notch and Axial EDM Notch normalized to 20 volts peak-to-peak (Vpp). This is the industry standard practice.

d. Bobbin indications that are determined to be other than wear, are evaluated using a rotating coil. Upon detection of a wear signal indication, a morphology determination is made with a bobbin probe. Wear indications are compared to the previous inspection data to determine if there is a change in signal characteristics. Any new wear indication, change in bobbin signal characteristics, or indications with no previous Motorized Rotating Pancake Coil data are characterized using a mid-frequency +Point probe and 0.115 Pancake rotating coil. Therefore, all suspect wear locations are inspected with a rotating probe to refute or confirm the presence of cracking. This evaluation is done in accordance with the CR3 Eddy Current Data Analysis Guidelines.

e. The difference between the number of tube ends examined with the bobbin coil versus the number examined with a rotating probe is due to the fact that there are sleeves installed in some of the upper tube ends of the steam generators. A rotating coil probe was used on all upper tube ends without a sleeve installed. For example, prior to 13R, there were 163 in-service sleeves in the A-OTSG. These tube ends were not included as part of the same inspection. Tubes with sleeves had their own inspections that included the parent tube material, the sleeve and rolled regions. The difference between the two numbers, 163 in A-OTSG and 159 in B-OTSG, is because the sleeves are considered as part of another inspection sample.

f. Each outage, 100% of the re-rolls inservice are examined with Rotating Pancake Coil (RPC) as required per the CR3 Improved Technical Specifications. The scan extent is from the upper tube end (UTE) to below the lowest roll transition (paying particular attention to the inspection plan for tubes with repair rolls and ensure the scan is far enough to capture the repair roll).

RAI Question 3

It was indicated that the primary-to-secondary leakage prior to plant shutdown was less than 5 gallons per day (gpd), and the leakage after 13R is less than 2 gpd. Presumably the reduction in leakage could be a result of the repair of through-wall flaws; however, no in-situ testing was performed. Please clarify the types of degradation detected during the outage (including orientation and location), the number of indications for each type of degradation, and discuss the sizes of the larger indications of each of these types of indications. Tube end cracks (i.e., those near the cladding) and first span intergranular attack indications need not be included in this information; however, indications associated with the roll transition or roll expanded area should be provided.

Response

The primary-to-secondary side leakage values of less than 5 gpd and then 2 gpd is not intended to imply that the leakage before the 13R outage was higher than after the outage. The 5 gpd limit was mentioned to identify that the leakage at CR3 was less than the lowest threshold limit from the EPRI Primary-To-Secondary Leak Guidelines. The actual leakage prior to the 13R outage was approximately 2.7 gpd. The leakage after the 13R outage is approximately 2.4 gpd. The difference between the two leakage rates is within the accuracy of the measurement.

The Tables provided in the next two pages have the information requested regarding orientation, location and size (voltage) for OTSG tube degradation (primarily Primary Water Stress Corrosion Cracking and Intergranular Attack). Indications near the cladding and first span intergranular attack are not included. Wear indications are provided in Special Report 04-01, Appendix 1.

The largest voltage indications from each of the different indication codes are identified below for each steam generator.

13R Largest Size (Voltage) Indications from Tables A-OTSG and B-OTSG

OTSG/Tube	Indication Code	Location	Length (Inches)	Depth (% TW)
A40-117	MAI	UTE - 0.63"	0.20	93
A70-66	SCI	UTE – 1.13"	0.38	77
A143-3	SVI	15S + 0.73"	0.44 x 0.29	48
A144-28	SAI	UTE – 1.19"	0.21	53
B80-109	SAI	UTE – 0.88"	0.19	57
B85-62	SVI	LTE + 1.11"	0.29 x0.38	69
B109-2	MAI	UTE – 4.14"	0.13	64
B134-66	MVI	UTE – 4.25"	0.27 x 0.44	40

MAI	Multiple Axial Indication
MVI	Multiple Volumetric Indication
SAI	Single Axial Indication
SCI	Single Circumferential Indication
SVI	Single Volumetric Indication
15S	15th Tube Support Plate
UTE	Upper Tube End
LTE	Lower Tube end
LTS	Lower Tubesheet Secondary Interface

A OTSG

Row	Tube	Volts	Degree	Indication	Landmark	Location
2	26	0.26	83	SAI	15S	-5.73
		0.31	86	MAI	15S	-7.3
		0.19	85	SAI	15S	-3.28
2	27	0.18	100	SAI	15S	-7.77
		0.21	101	SAI	15S	-6.63
13	67	0.21	105	SVI	15S	0.03
18	79	0.17	111	SVI	UTE	-4.07
25	3	0.34	24	SAI	UTE	-1.29
25	12	0.73	14	SAI	UTE	-1.42
27	51	0.56	23	SAI	UTE	-1.21
27	68	0.55	13	SAI	UTE	-1.41
28	100	0.55	17	SAI	UTE	-0.94
30	104	0.71	20	SAI	UTE	-0.99
40	85	0.71	21	SAI	UTE	-1.54
40	117	1.24	28	MAI	UTE	-0.63
44	17	0.5	16	SAI	UTE	-1.25
52	112	0.58	20	SAI	UTE	-1.18
52	118	0.81	22	SAI	UTE	-0.97
54	40	0.71	22	SAI	UTE	-1.16
55	100	0.61	26	SAI	UTE	-1.08
57	80	0.39	23	SAI	UTE	-1.47
58	115	0.58	32	MAI	UTE	-3.89
62	7	0.66	14	SAI	UTE	-1.32
65	73	1	24	SAI	UTE	-0.52
69	56	0.8	14	SAI	UTE	-0.57
69	127	0.64	20	SAI	UTE	-1.1
70	66	0.69	19	SCI	UTE	-1.13
75	95	0.6	22	MAI	UTE	-4.36
75	96	1.05	26	MAI	UTE	-4.22
77	50	0.2	83	SVI	UTS	0.21
80	102	0.72	13	SAI	UTE	-1.1
80	124	0.3	16	SAI	UTE	-1.02
81	9	0.91	20	SAI	UTE	-1.5
87	6	1.15	21	SAI	UTE	-0.6
87	56	0.82	28	SAI	UTE	-0.61
92	121	0.95	28	SAI	UTE	-0.95
96	111	1.22	24	SAI	UTE	-1.07
110	3	0.17	91	SVI	15S	-0.22
120	94	0.56	27	SAI	UTE	-1.06
143	3	1.21	76	SVI	15S	0.73
144	28	1.38	20	SAI	UTE	-1.19

B OTSG

Row	Tube	Volts	Degree	Indication	Landmark	Location
6	6	0.27	74	SAI	15S	-5.09
8	5	0.2	122	SVI	UTE	-4.51
14	27	0.36	20	SAI	UTE	-1.19
38	47	0.53	9	MAI	UTE	-1.17
44	3	1.02	16	SAI	UTE	-1.99
44	28	0.3	11	SAI	UTE	-1.19
46	2	0.47	59	SVI	LTS	0
50	82	0.16	90	SVI	UTE	-4.27
55	93	0.17	96	SVI	UTE	-3.15
55	122	0.34	19	SAI	UTE	-1.25
58	84	0.16	92	SVI	UTE	-4.19
72	31	1.05	17	SAI	UTE	-4.16
72	34	0.87	27	SAI	UTE	-3.65
73	15	1.11	33	SAI	UTE	-0.79
73	61	1.12	23	SAI	UTE	-0.72
80	6	0.6	16	SAI	UTE	-0.64
80	109	1.26	20	SAI	UTE	-0.88
81	10	0.82	23	SAI	UTE	-0.86
83	64	0.82	27	SAI	UTE	-0.71
85	62	0.98	22	SVI	LTE	1.11
89	94	0.13	122	SVI	UTE	-2.87
97	125	0.33	17	SVI	UTE	-1.12
98	97	0.84	18	SAI	UTE	-1.47
99	107	0.29	43	SAI	UTE	-0.84
100	33	0.52	25	SAI	UTE	-0.9
101	94	0.17	90	SVI	UTE	-3.36
109	2	0.7	24	MAI	UTE	-4.14
112	90	0.94	16	SAI	UTE	-1.43
114	1	0.35	80	SAI	15S	-1.62
121	83	0.69	17	SAI	UTE	-1.34
125	81	0.84	19	SAI	UTE	-4.24
127	79	0.76	15	SAI	UTE	-1.27
134	66	1.14	40	MVI	UTE	-4.25
137	4	0.82	26	SAI	UTE	-0.62
143	31	0.34	16	MAI	UTE	-1.14
149	33	0.41	138	SVI	UTE	-3.44

RAI Question 4

Several tubes were plugged preventively. Some of these preventive plugs were based on operating experience (OE) and some were plugged for wear. Please clarify the reasons for these preventive plugs (e.g., to address possible tube severance). In particular, discuss your criteria for when wear indications are preventively plugged.

Response

The plugged tubes identified in Special Report 04-01 as Preventative for OE were plugged to address the concern from industry issues related to the possibility of a tube severance event. These issues were identified in NRC Information Notice (IN) 2002-02 "Recent Experience with Steam Generator Plugged Tubes" and IN 2002-02, Supplement 1. The concern is that certain previously plugged tubes have the potential to sever and impact downstream or adjacent in-service tubes. By preventatively plugging and stabilizing the downstream and adjacent tubes, the impact from a potential severed tube is negated. Eddy Current inspections of the preventatively plugged tubes did not identify any severed tubes or any sign of degradation/wear due to an existing tube sever.

The plugged tubes listed as "Preventative Wear" were conservatively plugged based on the projected growth rates of wear indications at the tube support plates. The as-found percent thru-wall indications were all less than the plugging limit. The CR3 Degradation Assessment identifies the expected growth of wear indications and that value is used to project the wear extent at the next outage to determine whether a tube should remain in service.

RAI Question 5

Several tubes with sleeves were plugged for obstructions. Clarify the extent of the obstruction, the location of the obstruction, whether the tube/sleeve had adequate integrity (e.g., would the joints still have met all design criteria), identify when the sleeves were installed, the potential for the associated degradation mechanism to affect other sleeved tubes, and the technical basis for your conclusions. Also address your basis for not expanding the scope of the sleeve inspections based on these results.

Response

The tubes plugged for obstruction were plugged because the probe could not traverse the upper tube end of the sleeves due to tube/sleeve end damage from previous loose parts. According to the Eddy-Current Analysis Guidelines, if a tube can not pass a probe through the entire length, the tube must be removed from service. There was no active degradation mechanism (rejectable indication) in the portions of the sleeve and tube examined. All rolled sleeve joints continued to meet their design criteria as determined by the Condition Monitoring (CM) evaluation. The Alloy 690 sleeves were installed in 1994. There is no basis for sample expansion since no rejectable flaws were identified.

RAI Question 6

In some cases a 0.460-inch rotating probe was used for the examinations whereas in other instances a 0.520-inch rotating probe was used. In some cases, a 0.460-inch probe was used at a location that should have been able to pass a larger sized probe (e.g., it is not anticipated that a sleeve was installed at the location). Given that a smaller sized probe has a lower fill factor and may have larger amounts of noise, discuss the criteria you use to select your probes and address why the more typical sized probe is not used at all locations (excluding sleeved tubes).

Response

Rotating coil probes are surface riding probes and do not have a fill factor as do the bobbin probes. The smaller diameter probe is normally used for dent inspection.

RAI Question 7

A number of tubes were plugged for "rejected re-rolls." Please clarify whether these tubes were plugged because the re-roll installed during the 2003 outage was unacceptable or whether there was an indication in the re-rolled area (either following re-rolling in 2003 or in a previous re-roll). Discuss your operating experience with re-rolls (e.g., how many have been installed and how many have been plugged in subsequent outages as a result of degradation associated with the re-roll).

Response

In 13R, tubes plugged for rejected re-rolls were primarily plugged due to the failure to fully expand the re-roll during the initial installation of the re-roll in the lower tubesheet. Two tubes in one OTSG were plugged because an indication was found in a new re-roll.

A total of 1,010 tubes with re-rolls were installed in A-OTSG (880 Upper Tubesheet (UTS), 179 Lower Tubesheet (LTS)) and 8 of those tubes were removed from service due to re-roll indications. A total of 1,402 re-rolls were installed in B-OTSG (1,391 UTS, 13 LTS) and 21 tubes were removed from service due to re-roll indications.