Progress Energy

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

Ref: 10 CFR 50.36

August 3, 2006
3F0806-01

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 the 2005 Steam Generator Tube Inspections

References:
1. PEF letter, 3F1205-03, dated December 3, 2005, "Crystal River Unit 3 – Special Report 05-01: Once-Through Steam Generator (OTSG) Notifications Required Prior to MODE 4"
2. PEF letter, 3F0306-01, dated March 8, 2006, "Crystal River Unit 3 – Special Report 06-01: Results of the Once-Through Steam Generator Tube Inservice Inspection Conducted During Refueling Outage 14"
3. NRC letter, dated June 22, 2006, "Request For Additional Information Regarding the 2005 Steam Generator Tube Inspections at Crystal River Unit 3 (TAC Nos. MC9562, MD0220, MD0357)"

Dear Sir:

Florida Power Corporation, doing business as Progress Energy Florida, Inc. (PEF), submitted two special reports summarizing results from the 2005 steam generator tube inspections at Crystal River Unit 3 (CR3). Reference 1 provided information required prior to ascension into MODE 4 following Refueling Outage 14R pursuant to Improved Technical Specification (ITS) 5.7.2.c. Reference 2 provided a summary of the tube inspections within 90 days after breaker closure following the outage pursuant to ITS 5.7.2.e. After reviewing these documents, Nuclear Regulatory Commission (NRC) staff determined that additional information was needed in order to complete their review. A formal Request for Additional Information in the form of eleven questions was forwarded to CR3 (Reference 3). The first and second questions concern the Reference 1 letter; the remaining questions pertain to the Reference 2 letter. This submittal documents the PEF response to the NRC's information request and is being provided within 45 days of the date on the Reference 3 letter, as requested.

A047

If you have any questions regarding this submittal, please contact Mr. Paul Infanger, Supervisor, Licensing and Regulatory Programs at (352) 563-4796.

Sincerely, Ted E. Williams

T E Williams for

Michael J. Annacone
Engineering Manager

MJA/dar

Attachment: Crystal River Unit 3 Response to NRC Request for Additional Information Regarding the 2005 Steam Generator Tube Inspections

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

PROGRESS ENERGY FLORIDA, INC.

CRYSTAL RIVER UNIT 3

DOCKET NUMBER 50-302 / LICENSE NUMBER DPR-72

ATTACHMENT

Crystal River Unit 3 Response to NRC Request for Additional Information Regarding the 2005 Steam Generator Tube Inspections

Crystal River Unit 3 Response to NRC Request for Additional Information Regarding the 2005 Steam Generator Tube Inspections

Question 1

"In your December 3, 2005 letter, you indicated that postulated steam line break accident-induced leakage based on your 2005 inspection results was less than that projected from your previous (2003) inspection results. Clarify whether this was true for each of the degradation mechanisms for which leakage was projected. If there were any instances in which the projected leakage (based on 2003 results) was less than the as-found leakage (based on 2005 results) for a specific degradation mechanism, please discuss what corrective actions were taken."

Response 1

Degradation Mechanism	13R (2003) Operational Assessment (OA), gpm[1]		14R (2005) Condition Monitoring (CM), gpm[1]	
	OTSG-A [6]	OTSG-B	OTSG-A	OTSG-B
PWSCC [2]	0.08	0.01	0.01163	0.00227
ODSCC [3] / IGA [4]	0.02	0.02	N/A	N/A
TEC ARC [5] **	0.459	0.619	0.233	0.219

[1] (gallons per minute)
[2] (Primary Water Stress Corrosion Cracking)
[3] (Outside Diameter Stress Corrosion Cracking)
[4] (Intergranular Attack)
[5] (Tube End Cracking Alternate Repair Criteria)
[6] (Once-Through Steam Generator)
**The leakage calculation methodology was revised after 13R OA

The overall as-found (CM) postulated leakage in 2005 was less than the as-found (OA) leakage in 2005. No corrective actions were required.

Question 2

"On page 3 of 6 in your December 3, 2005, letter, you provided the in situ test pressures for several indications. Discuss the basis for these test pressures. For example, was the 5550 pounds per square inch test pressure based on a large break loss-of-coolant accident? In addition, confirm that these test pressures were based on your most limiting condition (e.g., a design basis accident with the appropriate safety factor or three times your normal operating pressure differential)."

Response 2

Content in the box below is from the December 3, 2005 letter, Attachment - Page 3 of 6, Item 3.

The following table contains information regarding the tubes that were subjected to a full-length pressure test:

OTSG	ROW	TUBE	FLAW TYPE	TEST PRESSURE (psig)	DEPTH (%TW)	LENGTH (inches)	ARC (inches)
A	3	30	Axial	4300	39	4.1"	NA
B	73	55	Circumferential	*5550	70	NA	**0.37"

*includes the pressure for MSLB axial loading.

**conservatively combined the ARC length of two close circumferential indications.

The in situ pressure tests for tubes A3-30 and B73-55 were performed in accordance with the EPRI Steam Generator In Situ Pressure Test Guidelines, Revision 2. The test sequence was Normal Operating Differential Pressure (NODP), Main Steam Line Break (MSLB), MSLB plus 500 pound step increments until (3 x NODP) was achieved. The Crystal River Unit 3 (CR3) steam generator design NODP is 1,275 pounds per square inch (psi) and the MSLB faulted differential pressure (DP) is 2,575 psi.

The indication in tube A3-30 was an axial indication. The test pressure to verify structural and leakage integrity of this tube was 4,300 psi (3 x NODP). This is the greater value of (1.4 x MSLB) or (3 x NODP). The 4,300 psi value is obtained by multiplying 1,275 psi (CR3 steam generator design NODP) by 3 and multiplying that by a correction factor for temperature and pressure gauge accuracy. This results in a desired minimum pressure of 4,273 psi, which was rounded up to 4,300 psi for testing purposes.

Structural integrity for tube B73-55 was demonstrated analytically for the limiting Small Break Loss of Coolant Accident (SBLOCA) condition. It did not require separate testing. The indication in tube B73-55 was circumferential and was only being tested to verify leakage integrity at MSLB conditions which includes the corresponding axial load from a MSLB event. It was tested to 5,550 psi to account for both pressure and axial loading conditions during the MSLB event. This particular tube is positioned at a radius of 10.3 inches from the center and has a small axial load during a SLB, but was tested to bound other similar flaws that may be identified in the future elsewhere in the tube bundle. Therefore, the 5,550 psi DP was used to create a worst case load condition to bound tubes at the periphery (maximum tube radius of 57.2 inches). The final test pressure at 5,550 psi therefore included conservatisms for both (3 x NODP) and MSLB axial load conditions.

The in situ pressure tests were performed to the most limiting design condition. SBLOCA axial loading was not required for tube B73-55 because the flaw was only being tested for leakage integrity and not structural integrity. The Large Break Loss of Coolant Accident (LBLOCA) is not considered the most limiting design condition for the CR3 steam generators. The issue of LBLOCA is currently being addressed by the Pressurized Water Reactor Owners Group working with the NRC to resolve this issue. For tube A3-30, the (3 x NODP) test is the most limiting condition. The test of B73-55 included both the (3 x NODP) and an axial load equal to the worst

case MSLB tube load. Therefore, both test pressures were based on the most limiting conditions for CR3.

Question 3

"On page 3 of 16 in your March 8, 2006, letter, you indicated that approximately 68 tubes were degraded. Confirm that all of these degraded tubes were a result of wear. If not, please discuss the basis for sizing the indications."

Response 3

Tube wear has a qualified sizing technique to measure the extent of through-wall wear. As defined in the CR3 Improved Technical Specifications, 5.6.2.10.4.a.4, "Degraded Tube means a tube containing degradation $\geq$ 20% through-wall but < 40% through-wall in the pressure boundary." All 68 tubes identified for the bobbin examination in the March 8, 2006 letter, Attachment - Page 3 of 6, Item 3, fell into this category, *degraded*, due to wear.

Question 4

"On page 10 of 16 in your March 8, 2006, letter, you indicated that as an additional check of the tube-end-cracking (TEC) leakage methodology, you projected the 14R leakage based on the 13R inspection results. Provide the data supporting your conclusion that the methodology over-predicted the as-found TEC leakage (e.g., new leakage, as-left leakage, etc.). Provide the data for both the upper and lower tubesheet in both steam generators."

Response 4

The TEC leakage projections shown in the tables below are based on CR3 Technical Specification License Amendment No. 222 leak rates and prediction methodology. The TEC data from outages prior to 14R (2005) are benchmarked using the currently approved methodology (Amendment No. 222) to allow a direct comparison of values. Since information in the tables below is based on the latest NRC approved methodology, it may not match previous submittal data that used older methodology. Data in the tables below represent the TEC leakage that would have been calculated in 2003 and projected to be as-found in 2005 had this methodology been used then. Note: There is no TEC data for the lower tube ends before the 13R outage. Therefore, any calculation needing data from that period will assume a value of 0.0 gpm.

The tables below identify the projected TEC leakage broken down by both upper (UTE) and lower (LTE) tube ends.

Projection of TEC Leakage for OTSG-A in 14R (Based on 13R [2003] Data)

13R Outage	As-Left Leakage, gpm	POD* Leakage, gpm	New Leakage, gpm	Trend Leakage, gpm	Total Projected 14R Leakage, gpm
UTE	0.128	0.057	0.084	0.000	0.269
LTE	0.007	0.001	0.007	0.007	0.022
Totals	0.135	0.058	0.091	0.007	0.291

* (Probability of Detection)

Actual as-found OTSG-A UTE TEC leakage in 14R was 0.223 gpm vs. 0.269 gpm projected.
Actual as-found OTSG-A LTE TEC leakage in 14R was 0.010 gpm vs. 0.022 gpm projected.

Because each OTSG-A UTE and LTE 14R projected leakage is greater than the actual as-found leakage, the Amendment No. 222 prediction method conservatively over-predicted the leakage.

Projection of TEC Leakage for OTSG-B in 14R (Based on 13R [2003] Data)

13R Outage	As-Left Leakage, gpm	POD Leakage, gpm	New Leakage, gpm	Trend Leakage, gpm	Total Projected 14R Leakage, gpm
UTE	0.123	0.066	0.132	0.003	0.324
LTE	0.038	0.008	0.040	0.040	0.126
Totals	0.161	0.074	0.172	0.043	0.450

Actual as-found OTSG-B UTE TEC leakage in 14R was 0.168 gpm vs. 0.324 gpm projected.
Actual as-found OTSG-B LTE TEC leakage in 14R was 0.051 gpm vs. 0.126 gpm projected.

Because each OTSG-B UTE and LTE 14R projected leakage is greater than the actual as-found leakage, the Amendment No. 222 prediction method conservatively over-predicted the leakage.

Question 5

"Clarify the statement on page 10 of 16 in your March 8, 2006, letter, where you indicate that the linear projection method is still considered adequate since the projected leakage for 15R is larger than the 14R as-found leakage. It would appear that a more appropriate comparison for determining the adequacy of the linear projection method would be comparing the leakage projection from the previous outage with the as-found leakage at the next outage."

Response 5

The context from which this statement came was describing how a review of trends for new leakage based on previous history gave predictable results, and was consistent with as-found data. For instance, while actual 14R data showed no unexpected jump in new leakage, OTSG-A had a minor increasing trend component which was added to the total 15R projection for new leakage. OTSG-B showed no such trend. The intended meaning of the statement in context was that the as-found TEC leakage for 14R was consistent with the predicted value, and the predicted 15R new leakage was only slightly increased over that for 14R. Since no unknown increasing effects were evident, the linear projection method could still be considered adequate.

CR3 agrees that a better overall process for determining the adequacy of the linear projection method is to compare the leakage projection from the previous outage with the as-found leakage at the next outage. This process was performed for the 13R (2003) to 14R (2005) outages and confirmed that the method was conservative for that operating cycle. See response to Question No. 4.

Question 6

"On page 13 of 16 in your March 8, 2006, letter, you indicated that one Alloy 600 welded plug, which was considered to be leaking, was removed and replaced. Discuss whether this leaking plug had adequate structural integrity including a summary of the basis for your conclusion."

Response 6

The Alloy 600 weld plug and stabilizer replaced during the 14R (2005) outage were originally installed in September 1979 in the hot leg. The corresponding cold leg plug is an Alloy 690 weld plug and was not replaced. The welded plug was designed to meet the stress and fatigue criteria of the original design code (ASME Section III, 1968 ed.).

In 1999, Crystal River 3 evaluated the structural integrity of welded plug B75-12 and concluded that the welded plug had adequate structural integrity. The results of the evaluation are documented in CR3 calculation S99-0626. Based on the effective throat of the weld, the evaluation concluded that the manually welded plug had sufficient strength to prevent catastrophic failure (including tubesheet failure) during normal and accident conditions for MSLB over the life of the steam generator. The weld plug in tube B75-12 was compared to an Areva thimble welded plug design, which also meets ASME Section III. The minimum effective throat of a thimble style plug is 0.043 inches and the equivalent throat of plug B75-12 was 0.092 inches. The equivalent throat of welded plug B75-12 was bounded by the stress calculation of a welded thimble plug.

In 2003, the welded cap plug style was reevaluated for the effect tubesheet bore dilations, due to accident conditions, would have on the structural integrity. The reevaluation determined there was no reduction in the allowable heat-up /cool-down cycles.

Therefore, the original design and subsequent evaluations in 1999 and 2003 all concluded that the weld plug had sufficient structural integrity for the life of the steam generator.

Question 7

"Regarding the in situ pressure test of tube A3-30, discuss the magnitude of the change in the size of the indication as a result of the pressure test."

Response 7

The indication in tube A3-30 increased from 0.60 volts to 2.43 volts and the length increased from 4.1" to 7.13".

Question 8

"Regarding your condition monitoring assessment, discuss the sources of accident-induced leakage and the amount of leakage assigned to each of those sources."

Response 8

Degradation Mechanism	14R CM (2005), gpm	
	OTSG-A	OTSG-B
PWSCC	0.01163	0.00227
ODSCC/IGA	N/A	N/A
TEC ARC	0.233	0.219
Re-roll	0.006	0.006
Plug Seal Weld	N/A	0.0007

Question 9

"Clarify the number and size of indications found in the unexpanded region of the tube within the upper and lower tubesheet. Indicate which indications were detected with the bobbin probe, rotating probe, or both probes."

Response 9

As identified in Appendix 3 of the March 8, 2006 letter, two indications were identified in OTSG-A, both in the upper tubesheet (UTS), that were only detected with the rotating coil. Twenty-three indications were identified in the OTSG-B, twenty-one in the UTS and two in the lower tube sheet (LTS). The indications identified on the table below are those indications 2" inboard of the tube end (UTE/LTE ±2 inches) to the secondary face of the tubesheet (UTS/LTS). The indications in the tubesheets are characterized as single / multiple axial (SAI/MAI), single / multiple circumferential (SCI/MCI), or single / multiple volumetric (SVI/MVI) based on the rotating coil examination. The bobbin coil data was not used to evaluate for flaws in the tubesheet region since entire tubesheet areas were examined with the rotating coil.

OTSG	ROW	TUBE	VOLTS	DEG	IND	LOCATION
A	41	112	0.12	91	SAI	UTS +0.30
A	135	33	0.14	83	SAI	UTE -2.22
B	10	12	0.38	103	SAI	UTS +18.2
B	11	5	0.16	96	SAI	UTS +20.4
B	11	5	0.27	97	SAI	UTS +19.3
B	22	34	0.68	87	SAI	UTE -2.88
B	37	68	0.74	35	SAI	UTE -3.54
B	49	18	0.49	63	SAI	UTS +17.0
B	52	1	0.69	23	SAI	UTE -4.11
B	52	113	0.24	70	SAI	UTS +18.5
B	58	3	0.2	88	SVI	UTE -4.05
B	70	35	0.74	19	SAI	UTE -4.07
B	70	49	0.46	29	SAI	UTE -4.72
B	73	55	1.05	66	SCI	UTS +0.31

OTSG	ROW	TUBE	VOLTS	DEG	IND	LOCATION
B	73	55	1.28	59	SCI	UTS +0.22
B	79	62	0.2	106	SVI	UTS +0.16
B	92	114	0.57	28	SAI	UTE -4.02
B	102	39	0.19	116	MVI	UTE -3.37
B	110	42	0.16	110	SVI	UTE -4.09
B	120	40	0.15	120	SVI	UTE -2.63
B	125	6	2.08	20	SAI	LTE +5.64
B	125	6	0.84	14	SAI	LTE +3.00
B	141	63	0.67	29	MAI	UTE -4.49
B	143	62	0.32	38	MCI	UTE -3.29
B	148	4	0.42	36	MAI	UTE -4.06

Question 10

"Clarify the number and size of indications attributed to groove intergranular attack (IGA)/stress corrosion cracking."

Response 10

OTSG-A Axial ODSCC/IGA Indications in the Upper Bundle										
Row	Col	Loc	Inch1	Inch2	Indi-cation	Deg	Flaw Depth	Axial Extent	Circ Extent	Volts
3	6	06S	-1.02		SAI	69	57	0.14		0.44
3	30	15S	-0.96	-2.71	SAI	74	51	1.75		0.2
3	30	15S	-2.64	-6.26	SAI	94	27	3.62		0.31
3	30	15S	-3.33	-7.43	SAI	84	39	4.1		0.6
3	32	15S	-0.92	-1.34	SAI	110	6	0.42		0.11
3	32	15S	-1.19	-2.91	SAI	81	43	1.72		0.37
3	32	15S	-3.15	-6.87	SAI	80	44	3.72		0.52
3	32	15S	-3.21	-3.95	SAI	86	37	0.74		0.23
3	32	15S	-5.36	-6.24	SAI	87	35	0.88		0.24
3	32	15S	-6.61	-7.25	SAI	99	20	0.64		0.11
3	32	15S	-4.38	-5.05	SAI	85	38	0.67		0.18
4	34	15S	-1	-6.7	SAI	88	34	5.7		0.45
4	34	15S	-0.99	-1.29	SAI	85	38	0.3		0.15
4	34	15S	-3.14	-5.58	SAI	83	40	2.44		0.41
5	45	15S	-4.43		SAI	94	1	0.33		0.38
23	93	14S	-7.31		SAI	17	0	0.24		0.48
35	89	14S	0.13		SAI	55	0	0.15		0.45
35	89	14S	-0.05		SAI	34	0	0.19		0.82
41	112	UTS	0.3		SAI	91	16	0.25		0.12
64	69	15S	7.28		SAI	99	20	0.19		0.15
64	69	15S	7.65		SAI	91	30	0.29		0.23
64	69	15S	10.81		SAI	98	22	0.27		0.13
76	123	15S	-1.01		SAI	121	22	0.3		0.26

OTSG-A Axial ODSCC/IGA Indications in the Upper Tubesheet Crevice										
135	33	UTE	-2.22		SAI	83	37		0.75	0.14

OTSG-B Axial ODSCC/IGA Indications in the Upper Bundle										
Row	Col	Loc	Inch1	Inch2	Indi-cation	Deg	Flaw Depth	Ax Ext	Circ Ext	Volts
10	3	15S	-4.84		SAI	93	1	0.6		0.51
40	116	09S	-0.33		SAI	90	10	0.19		0.33
52	113	14S	13.17		SAI	31	78	0.17		0.3
56	126	15S	-1.6		SAI	87	25	1.47		0.37
57	127	15S	0.11		SAI	101	0	0.63		0.74
57	127	15S	-2.45		SAI	76	54	1.25		0.35
64	128	15S	-4.54		SAI	94	5	0.41		0.16
73	130	15S	3.08		SAI	80	42	0.23		0.21
73	130	15S	4.6		SAI	81	42	0.34		0.16
117	86	UTS	-0.47		SAI	73	58	0.61		0.41
126	99	15S	-4.6		MAI	89	30	1.75		0.28
126	99	15S	-1.21		SAI	97	4	0.31		0.1
129	6	UTS	-7.38		SAI	65	69	0.3		0.12
140	67	12S	-6.62		SAI	62	68	0.5		0.36
OTSG-B Axial ODSCC/IGA Indications in the Upper Tubesheet Crevice										
10	12	UTS	18.28		SAI	103	21	5.04		0.38
11	5	UTS	22.18		MAI	94	14	0.18		0.36
11	5	UTS	22.48		SAI	91	24	0.42		0.45
11	5	UTS	20.4		SAI	96	8	0.95		0.16
11	5	UTS	19.34		SAI	97	4	0.39		0.27
14	34	UTE	-1.93		SAI	75	56	1.5		0.75
22	34	UTE	-2.88		SAI	87	32	5.16		0.68
49	18	UTS	17.04		SAI	63	75	4.34		0.49
52	113	UTS	18.56		SAI	70	65	2.42		0.24

Question 11

"A number of volumetric indications (other than first span IGA and wear) were identified. Discuss the cause of these indications. Confirm that all volumetric indications (other than first span IGA and wear) were plugged."

Response 11

The exact cause of the indications can not be determined without destructive analysis. Therefore, the cause of the indications can only be surmised based on the eddy current response from the indications. Volumetric-in-nature indications are indicative of IGA or localized pitting. The indications are similar to indication response from pulled tubes with IGA. All tubes with volumetric indications were either plugged or rerolled.