NEXTera ENERGY POINT BEACH

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TS 5.6.8

U. S. Nuclear Regulatory Commission
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Point Beach Nuclear Plant, Unit 1
Docket No. 50-266
Renewed License No. DPR-24

Fall 2008 Unit 1 (U1R31)
Steam Generator Tube Inspection Report

References: (1) FPL Energy Point Beach, LLC letter to NRC, Supplement to License Amendment Request 257, Technical Specification 5.5.8 and 5.6.8, Steam Generator Program & Steam Generator Tube Inspection Report Interim Alternate Repair Criteria (IARC) for Steam Generator Tube Rupture, dated July 18, 2008 (ML082040226)

Pursuant to the requirements of Point Beach Nuclear Plant (PBNP) Technical Specification (TS) 5.6.8, "Steam Generator Tube Inspection Report," NextEra Energy Point Beach, LLC, is submitting the 180-day Steam Generator Tube Inspection Report. The enclosure to this letter provides the results of the fall 2008, Unit 1 (U1R31) steam generator tube in-service inspections.

Summary of Regulatory Commitments

This submittal fulfills the following Regulatory Commitment made in Reference (1):

- The ratio of 2.5 will be used in completion of both the condition monitoring (CM) and operational assessment (OA) upon implementation of the IARC. For example, for the CM assessment, the component of leakage from the lower 4 inches for the most limiting steam generator during the prior cycle of operation will be multiplied by a factor of 2.5 and added to the total leakage from any other source and compared to the allowable accident analysis leakage assumption. For the OA, the difference in leakage from the allowable limit during the limiting design basis accident minus the leakage from the other sources will be divided by 2.5 and compared to the observed leakage. An administrative limit will be established to not exceed the calculated value.

If you have questions or require additional information, please contact me at 920/755-7427.

Very truly yours,

NextEra Energy Point Beach, LLC

James Costedio
Licensing Manager
Point Beach Nuclear Plant

Enclosure

cc: Administrator, Region III, USNRC
Project Manager, Point Beach Nuclear Plant, USNRC
Resident Inspector, Point Beach Nuclear Plant, USNRC
PSCW

ENCLOSURE

NEXTERA ENERGY POINT BEACH, LLC
POINT BEACH NUCLEAR PLANT, UNIT 1

FALL 2008 UNIT 1 (U1R31)
STEAM GENERATOR TUBE INSPECTION REPORT

1. Background

The Point Beach Nuclear Plant (PBNP) steam generator (SG) tube inspection program for the fall 2008, Unit 1 Refueling Outage 31 (U1R31) was conducted in accordance with the requirements of PBNP Technical Specification (TS) 5.5.8. PBNP Unit 1 entered MODE 4 on November 9, 2008, following this in-service inspection. PBNP determined that U1R31 is within the third sequential in-service inspection period of 60 effective full power months (EFPM) following the first in-service inspection. Inspections conducted during U1R31 meet the TS requirements for the first half of the period and mark the midpoint inspection of the 60 EFPM period.

PBNP Unit 1 SGs are Westinghouse Model 44F replacement SGs with 3214 0.875-inch outer diameter, 0.050-inch wall, Inconel Alloy 600 thermally-treated tubes. The tubes are on a 1.234-inch square pitch and were hydraulically expanded the full depth of the tubesheet with the exception of the tube at Row 38/Column 69 in SG A which is not fully expanded the full length of the tubesheet. The first eight rows of U-bends were stress relieved after bending. The tubes are supported by a stainless steel flow distribution baffle with round holes, six stainless steel tube support plates with quatrefoil holes and two sets of chrome plated Inconel anti-vibration bar (AVB) assemblies. The original PBNP Unit 1 SGs were replaced during Refueling Outage 11 in 1983. The replacement SGs have accumulated approximately 20.4 effective full power years of operation.

A full bundle chemical cleaning was conducted during U1R31 on both SG A and SG B. By visual inspections, all previously observed tube support plate quatrefoil blockage has been removed. This blockage was reported in Reference 1.

The U1R31 SG tube inspections were conducted on both SG A and SG B and consisted of the following:

a. Scope of Inspections Performed on Each SG

Tube end to tube end bobbin coil inspections were performed on all accessible (not plugged) tubes in PBNP Unit 1 SG A and SG B during U1R31. Rotating probe techniques (i.e., +Point^{TM}) were used to further disposition certain indications reported with the bobbin coil, and to inspect locations where the bobbin coil is not qualified for use. Rotating +Point^{TM} inspections were also performed on 100% of all hot leg top of tubesheet areas. The purpose of the inspection was to identify existing or potential forms of SG degradation as detailed in Section (c).

The initial U1R31 eddy current test (ECT) inspection for PBNP Unit 1, SG A and SG B is summarized as follows:

Unit 1 SG A

<u>Bobbin coil inspections included – all accessible tubes (3,210 tubes):</u>

Rows 1 and 2 – straight length inspection only (183 tubes)

- Straight sections from the hot leg – 183 tubes
- Straight sections from the cold leg – 183 tubes

Rows 3 and above – full length inspection (3,027 tubes)

- Rows 3 and 4 – straight sections from the hot leg – 183 tubes
- Rows 3 and 4 – straight sections plus U-bend from the cold leg – 183 tubes
- Rows 5 and above – full length from the cold leg – 2,844 tubes

<u>+Point™ inspection:</u>

- Hot Leg Top of Tubesheet ±3" – 100% of all tubes (3,210 tubes)
- Hot Leg Tubesheet Full Depth (TEH – TSH +3") (1,713 tubes)
- Cold Leg Top of Tubesheet ±3" – 100% of peripheral tubes (530 tubes)
- ~50% Tight Radius U-Bends in Rows 1 and 2 (95 tubes)

Unit 1 SG B

<u>Bobbin coil inspections – all accessible tubes (3208 tubes):</u>

Rows 1 and 2 – straight length inspection only (182 tubes)

- Straight sections from the hot leg – 182 tubes
- Straight sections from the cold leg – 182 tubes

Rows 3 and above – full length inspection (3,026 tubes)

- Rows 3 and 4 – straight sections from the hot leg – 184 tubes
- Rows 3 and 4 – straight sections plus U-bend from the cold leg – 184 tubes
- Rows 5 and above – full length from the cold leg – 2,842 tubes

<u>+Point™ inspection:</u>

- Hot Leg Top of Tubesheet ±3" – 100% of all tubes (3,208 tubes)
- Hot Leg Tube End + 5" (TEH – TEH +5") (965 tubes)
- Hot Leg Tubesheet Full Depth (TEH – TSH +3") (694 tubes)
- Cold Leg Top of Tubesheet ±3" – 100% of peripheral tubes (529 tubes)
- ~20% Tight Radius U-Bends in Rows 1 and 2 (40 tubes)

Upon completion of the initial inspection program for SG A and SG B, diagnostic and special interest (SI) inspections based on historical data and the results of the initial bobbin and +Point™ inspections were performed to characterize and/or size the identified indications. This includes dents and dings equal to or less than 5.0 volts in the straight length free spans which were screened with bobbin probes (refer to Section (d)). Dents and dings in the following categories were examined with the +Point™ probe:

- All dents and dings reported with the bobbin coil in the U-bend region
- All dents and dings reported with the bobbin coil at structures
- All dents and dings reported with the bobbin coil >5.00 volts in the freespan region

b. Active Degradation Mechanisms Found

During the U1R31 SG ECT inspection, no crack-like indications were reported and no tubes required plugging. No active degradation mechanisms were found. Wear degradation described in Section (d), Tables 1 and 2, is not considered active, based on industry guidance. One tube in SG A was preventatively plugged as described in Section (e).

c. Nondestructive Examination Techniques Utilized for Each Degradation Mechanism

Existing Degradation Mechanism	Examination Technique	% Sample (SG A and B)
AVB Wear	Bobbin	100%
Tube Support Plate Wear	Bobbin	100%
Mechanical/Loose Part Wear	Bobbin, +Point™; visual	100% bobbin; 100% HL TTS (±3"), CL Periphery TTS (±3"); visual inspection

Potential Degradation Mechanism	Examination Technique	% Sample (SG A and B)
Mechanical/Loose Part Wear	Bobbin; +Point™; visual	100% bobbin; 100% HL TTS (±3"), CL Periphery TTS (±3"); visual inspection
PWSCC in Tubesheet/Tube Ends	+Point™	SG A – 50% HL tubesheet full depth SG B – 50% HL tubesheet full depth (20% TTS +3" to tube end +30% -17" to tube end for tubes inspected in U1R30)
ODSCC Tubesheet Transition Zone	+Point™	100% HL TTS (±3")
ODSCC in sludge pile	Bobbin; +Point™	100% bobbin; 100% +Point™ HL TTS ±3"
ODSCC at Tube support plates	Bobbin; +Point™	100% bobbin; +Point™ all detected from bobbin

Potential Degradation Mechanism	Examination Technique	% Sample (SG A and B)
ODSCC Low Row U-bend	+Point™	SG A - 50% Row 1/Row 2 SG B - 20% Row 1/Row 2
ODSCC Ding (Freespan)	Bobbin; +Point™	100% Bobbin 100% +Point™ (≥ 5V freespan)
ODSCC Ding/Dent (U-bend and supports)	Bobbin; +Point™	100% Bobbin 100% +Point™ (all at AVBs, TSPs & U-bends)
PWSCC Low Row U-bends	+Point™	SG A - 50% Row 1/Row 2 SG B - 20% Row 1/Row 2
PWSCC Tubesheet Transition Zone	+Point™	100% HL TTS (±3")
Pitting	+Point™	All based on Bobbin indication

Legend:

ODSCC	Outside diameter stress corrosion cracking
PWSCC	Primary water stress corrosion cracking
HL	hot-leg
CL	cold-leg
TSP	tube support plate
AVB	anti-vibration bar
TTS	top of tubesheet

Transition zone refers to the area near the top of tubesheet (TTS) inspected over a range of at least +3" to -3".

d. Location, Orientation (if Linear), and Measured Sizes (if Available) of Service Induced Indications

Anti-Vibration Bar (AVB) Wear - SG A

There were 89 indications in 48 tubes in SG A with indications of wear at the AVBs. All 89 AVB wear indications were sized with the bobbin coil. Two locations (Row 35/Column 56 and Row 38/Column 43), which showed the deepest wear reported, were additionally inspected with the +Point™ coil to further evaluate whether they were one or two sided. The results showed two-sided wear with thru wall measurements comparable to the bobbin measurements. None of these indications were determined to be repairable per engineering disposition and all remained in service. Table 1A shows all AVB wear indications.

Table 1A – Anti-Vibration Bar Wear, % Through-Wall, SG A

Row	Column	Location	% Through Wall
22	8	AVB3	3
		AVB4	3
32	14	AVB2	4
		AVB3	7
		AVB4	5
33	18	AVB3	19
		AVB4	10
35	18	AVB2	9
38	22	AVB2	7
		AVB3	9
		AVB4	6
40	25	AVB1	6
		AVB2	7
		AVB3	7
40	27	AVB3	6
34	33	AVB1	8
		AVB2	6
33	37	AVB3	5
		AVB4	10
45	41	AVB1	7
		AVB4	8
40	42	AVB1	7
45	42	AVB1	10
35	43	AVB3	9
		AVB4	11
38	43	AVB1	27
		AVB2-	19
		AVB2+	24
45	43	AVB1	7
		AVB4	9
40	44	AVB3	9
40	47	AVB3	10
33	48	AVB3	8
		AVB4	4
45	49	AVB1	4
		AVB2	4
		AVB4	7
45	50	AVB4	6
45	51	AVB4	6
45	52	AVB2	7

Row	Column	Location	% Through Wall
		AVB3	6
		AVB4	5
11	53	AVB4	7
19	54	AVB1	7
		AVB2	12
		AVB3	8
		AVB4	13
38	54	AVB3	20
		AVB4	8
35	56	AVB1	21
		AVB2	33
33	57	AVB1	4
19	61	AVB1	12
		AVB2	14
		AVB4	6
42	61	AVB4	6
24	63	AVB1	8
31	63	AVB2	13
		AVB3	7
34	65	AVB3	9
		AVB4	14
33	66	AVB1	16
		AVB2	13
		AVB3	5
32	68	AVB1	10
		AVB2	8
39	68	AVB2	5
		AVB3	5
		AVB4	5
34	69	AVB1	6
		AVB2	11
39	69	AVB3	7
27	71	AVB2	8
		AVB3	14
		AVB4	8
32	71	AVB2	14
		AVB3	8
33	71	AVB2	16
		AVB3	10
32	78	AVB3	2
31	79	AVB3	5
32	79	AVB1	4

Row	Column	Location	% Through Wall
29	81	AVB2	4
26	83	AVB3	6
26	84	AVB1	4
		AVB2	3
24	85	AVB2	5
15	87	AVB2	5
		AVB3	5

The (+) and (-) symbols indicate wear on different edges of the AVB

<u>Anti Vibration Bar (AVB) Wear - SG B</u>

There were 64 indications in 43 tubes in SG B with indications of wear at the AVBs. All 64 AVB wear indications were sized with the bobbin coil. None of these indications were determined to be repairable per engineering disposition and all remained in service. Table 1B shows all AVB wear indications.

Table 1B – Anti-Vibration Bar Wear, % Through-Wall, SG B

Row	Column	Location	% Through Wall
24	13	AVB2	7
28	13	AVB2	7
32	14	AVB2	7
14	15	AVB3	8
33	16	AVB1	4
33	17	AVB2	8
34	17	AVB2	8
34	18	AVB2	5
35	18	AVB2	6
38	22	AVB1	7
25	23	AVB3	6
31	25	AVB4	6
41	29	AVB1	5
		AVB4	6
42	31	AVB4	7
32	32	AVB3	10
		AVB4	7
42	32	AVB1	11
23	33	AVB1	8
		AVB2	14
		AVB3	24
		AVB4	4
42	33	AVB1	7

Row	Column	Location	% Through Wall
19	36	AVB3	8
29	40	AVB2	8
28	41	AVB4	7
32	44	AVB3	5
45	44	AVB1	6
		AVB2	5
32	46	AVB1	6
		AVB2	14
		AVB3	18
		AVB4	12
45	46	AVB1	7
16	47	AVB2	8
32	49	AVB1	17
		AVB2	13
44	50	AVB3	9
44	54	AVB1	9
		AVB3	6
29	55	AVB1	12
		AVB3	4
22	58	AVB1	9
		AVB2	19
		AVB3	17
		AVB4	13
39	69	AVB2	7
		AVB3	6
32	70	AVB1	12
		AVB2	16
33	71	AVB1	18
		AVB2	9
		AVB3	4
16	73	AVB2	7
37	73	AVB3	9
36	74	AVB1	5
		AVB4	6
34	75	AVB2	9
16	77	AVB3	6
18	77	AVB3	8
17	79	AVB2	8
28	79	AVB2	8
23	86	AVB2	7
		AVB3	10

Tube Wear at Broached Tube Support Plate (TSP)

There were four distorted support indication (DSI) codes reported in tubes in SG A and one in SG B. All of these indications were at broached supports reported from bobbin coil and were dispositioned as wear at one land contact point and sized with +Point™. The results of the sizing showed wear at one land contact point at each of the reported broached locations with wear depths ranging from 10% to 14% through wall. Table 2 shows all TSP wear indications.

Table 2 – Wear at Broached Tube Support Plates, % Through Wall

SG	Row	Column	% Through Wall	Support
A	39	24	13	03C
A	41	65	14	02C
A	39	67	10	02C
A	21	85	13	02C
B	34	18	12	01H

Legend:

N/I Not Inspected
N/R Not Reported
- No indication

Mechanical Wear Indications above the Top of Tubesheet Hot (TSH) and Cold (TSC) Legs

There were 27 tubes with 34 indications in SG A. The totals in SG B were one tube with one indication previously reported (Reference 2). The majority of these were on the extreme outer periphery of the generator with indications attributed to mechanical wear above the top of tubesheet. When both bobbin and +Point™ probes detected clearly defined indications at these locations, the indications were sized using the volumetric flaw standard and data analysis technique specified in EPRI technique ETSS 21998.1 for the +Point™ coil. When bobbin detection and +Point™ geometric distortion were present the code, GEO was used to identify the tube for further attention in future inspections. The suspected cause of these indications is attributed to sludge lancing equipment. Results of the sized mechanical wear indications are listed in Table 3.

Table 3 – Sized Mechanical Wear, SG A and SG B

SG	Row	Column	Location/Inch		% Through Wall
A	37	20	TSH	0.76	2
A	41	28	TSH	0.63	7
A	42	30	TSH	0.58	6
A	43	33	TSH	0.64	7
A	44	36	TSH	0.64	5
A	45	41	TSH	0.72	5
A	45	42	TSH	0.79	2
A	45	43	TSH	0.72	2
A	45	44	TSH	0.64	4
A	45	45	TSH	0.61	2
A	45	45	TSH	0.61	10
A	45	46	TSH	0.64	3
A	45	47	TSH	0.64	3
A	43	60	TSH	0.68	11
A	42	63	TSH	0.66	19
A	33	78	TSH	0.71	1
A	31	80	TSH	0.69	9
B	1	92	TSH	+6.2	6

<u>Wear Due to Loose Parts</u>

The current 2008 data also showed mechanical wear attributed to a loose part in SG B at tube location Row 1/Column 5. The analysis of this tube determined that there were no interfering signals present at the locations of the wear (this was during the post-chemical cleaning/post-sludge lancing wave of the inspection) and as such, the wear indication of the tube with both bobbin and +Point™ detection was sized using the volumetric flaw standard and used the EPRI technique ETSS 21998.1. The result of the wear signal was sized with the +Point™ at 17% through wall. Visual inspections showed no visible loose parts present. Since the depth is below the repair criterion and further wear is unlikely, the tube was determined by engineering disposition to be acceptable to remain in service.

Table 4 – Loose Part Wear

SG	Row	Column	Location/Inch U1R31		% Through wall		
					2008 U1R31	2007 U1R30	2004 U1R28
B	1	5	TSC	0.42	17	-	-

ECT Indications from Possible Loose Parts (PLP)

Four PLP indications were reported during the pre-chemical cleaning/pre-sludge lancing wave of the inspection. There was one in SG A and three in SG B. After the chemical cleaning/sludge lancing was performed, these locations were re-tested. The results showed that for two of the locations, the PLP signal was gone. These locations were edited to no loose part (NLP). Details of the remaining two tubes with PLP indications are shown in Table 5.

Table 5 – PLP Indication Summary

SG	Row	Column	Location	Elevation
A	13	40	TSH	+2.03"
B	2	75	TSH	+0.22"

No degradation was observed in conjunction with these two indications. The indications were not reported in the 2005 or 2007 inspections. All tubes adjacent to these indications were also tested with +Point™ in the area of interest. Visual inspections following cleaning activities showed no loose parts present.

Ding/Dent (DNG/DNT) Indications

There were 546 total DNG/DNT indications identified in 393 tubes that were ≥2.00 volts. These totals include both SG A and SG B.

As stated in Section (a), dents and dings equal to or less than 5.0 volts in the straight length freespans were screened with bobbin probes. Dents and dings in the following categories were examined with the +Point™ coil:

- all dents and dings reported with the bobbin coil in the U-Bend region
- all dents and dings reported with the bobbin coil at structures
- all dents and dings reported with the bobbin coil >5.00 volts in the freespan region

A resolution review was required for the bobbin coil DNG/DNT indications reported during the U1R31examination to confirm that the indications were present in the 1995 benchmark examination. Indications reported as DNG would indicate that a historical review was performed and that the DNG indication was present in the 1995 data. If the indication was not present in the 1995 raw data, the indication was reported as a DNT to indicate the DNG was introduced to the tubing sometime after the benchmark inspection. During the U1R31 examination, there was one DNT reported in a peripheral tube approximately one inch above the hot leg top-of-tubesheet in SG A. This single DNT indication was not present in the 1995 data, and is attributed to damage caused by the use of sludge lancing equipment used during SG secondary-side maintenance operations performed sometime after the benchmark inspection in 1995.

Distorted Dent Indications (DDI)

There were 14 DDI indications reported in 13 tubes. These totals include both SG A and SG B (this is further explained below).

DDI signals reported in both SG A and SG B were also reviewed and compared to the benchmark inspection in 1995. All of the DNT and DDI indications were examined with the +Point™ coil.

Although geometric distortions were observed with the +Point™ coil at both the DNT and DDI locations, no degradation was associated with these indications.

e. Number of Tubes Plugged During the Inspection Outage for Each Active Degradation Mechanism

No SG tubes required plugging as a result of this inspection. One tube in SG A at Row 38/Column 69 was preventatively plugged due to not being hydraulically expanded the full depth of the tubesheet.

f. Total Number and Percentage of Tubes Plugged To Date

The total number and percentage of tubes plugged to date for SG A is 5 of 3,214 total tubes, or 0.15%. The total number and percentage of tube plugged to date for SG B is 6 of 3,214 total tubes, or 0.19%.

g. The Results of Condition Monitoring, Including the Results of Tube Pulls and In-Situ Testing

Condition Monitoring was completed. SG A and SG B did not exceed any performance criteria during the last operating cycles (since U1R29 and U1R30, respectively). Tube pulls and in-situ testing were neither required nor conducted.

h. The Effective Tube Plugging Percentage for All Plugging in Each SG

No tube repair methods are approved for PBNP Unit 1. Therefore, the effective plugging levels are as stated per Section (f) above.

i. Following completion of an inspection performed in Unit 1 Refueling Outage 31 (and any inspections performed in the subsequent operating cycle), the number of indications and location, size, orientation, whether initiated on primary or secondary side for each service-induced flaw within the thickness of the tubesheet, and the total of the circumferential components and any circumferential overlap below 17 inches from the top of the tubesheet as determined in accordance with TS 5.5.8

There were no observed indications in association with a service-induced flaw for the inspections performed within the tubesheet.

j. **Following completion of an inspection performed in Unit 1 Refueling Outage 31 (and any inspections performed in the subsequent operating cycle), the primary to secondary LEAKAGE rate observed in each steam generator (if it is not practical to assign leakage to an individual SG, the entire primary to secondary LEAKAGE should be conservatively assumed to be from one steam generator) during the cycle preceding the inspection which is the subject of the report**

As reported previously (Reference 2 and Reference 3) PBNP has a primary-to-secondary leak rate of approximately 0.3 gpd which continued to be detected for the cycle preceding U1R31. The low leakage rate precluded accurately differentiating leakage between individual SGs. Therefore, it is assumed that the total leakage is from a single SG.

k. **Following completion of an inspection performed in Unit 1 Refueling Outage 31 (and any inspections performed in the subsequent operating cycle), the calculated accident leakage rate from the portion of the tube below 17 inches from the top of the tubesheet for the most limiting accident in the most limiting steam generator**

The calculated accident induced leakage (AIL) rate from the SG is assumed to be from the area below 17 inches from the top of the tubesheet and all from one SG. Multiplying the leak rate of 0.3 gpd by a factor of 2.5, per Reference 4, equates to an AIL rate of 0.75 gpd. This is below the technical specification AIL of 500 gpd per SG for the most limiting accident.

<u>References</u>

1. Letter from FPL Energy Point Beach, LLC to NRC, Response to Request for Additional Information, Spring 2007 Unit 1 (U1R30) Steam Generator Tube Inspection Report, dated March 14, 2008 (ML 080770187)

2. Letter from FPL Energy Point Beach, LLC to NRC, Spring 2007 Unit 1 (U1R30) Steam Generator Tube Inspection Report, dated October 25, 2007 (ML072990108)

3. Letter from Nuclear Management Company, LLC to NRC, Supplement 1 to License Amendment Request 248; Technical Specification 5.5.8, Steam Generator Program, dated January 19, 2007 (ML070220084)

4. Letter from NRC to FPL Energy Point Beach, LLC, Point Beach Nuclear Plant, Unit 1 – Issuance of Amendment, RE: Technical Specification 5.5.8 and 5.6.8 (TAC NO. MD8800), dated October 7, 2008 (ML082540883)