NEXTera ENERGY SEABROOK

November 2, 2011

SBK-L-11207
Docket No. 50-443

U.S. Nuclear Regulatory Commission
Attention: Document Control Desk
One White Flint North
11555 Rockville Pike
Rockville, MD 20852

Seabrook Station
Response to Request for Additional Information
NextEra Energy Seabrook License Renewal Application
Request for Additional Information - Set 16

References:

1. NextEra Energy Seabrook, LLC letter SBK-L-10077, "Seabrook Station Application for Renewed Operating License," May 25, 2010. (Accession Number ML101590099)
2. NRC Letter "Request for Additional Information for the Review of the Seabrook Station License Renewal Application" (TAC NO. ME4028) – Request for Additional Information Set 16," October 7, 2011. (Accession Number ML11278A069)
3. NextEra Energy Seabrook, LLC letter SBK-L-11069, "Seabrook Station Response to Request for Additional Information, NextEra Energy Seabrook License Renewal Application – Set 12," April 22, 2011. (Accession Number ML11115A116)
4. NextEra Energy Seabrook, LLC letter SBK-L-11015, "Seabrook Station Response to Request for Additional Information, NextEra Energy Seabrook License Renewal Application – Sets 6, 7 and 8," February 3, 2011. (Accession Number ML110380081)
5. NextEra Energy Seabrook, LLC letter SBK-L-11154, "Seabrook Station Response to Request for Additional Information, NextEra Energy Seabrook License Renewal Application – Set 15," August 11, 2011. (Accession Number ML11227A023)
6. NextEra Energy Seabrook, LLC letter SBK-L-11173, "First Annual Update to the Seabrook Station License Renewal Application," August 25, 2011. (Accession Number ML11241A142)

In Reference 1, NextEra Energy Seabrook, LLC (NextEra) submitted an application for a renewed facility operating license for Seabrook Station Unit 1 in accordance with the Code of Federal Regulations, Title 10, Parts 50, 51, and 54.

A144

NRR

In Reference 2, the NRC requested additional information in order to complete its review of the License Renewal Application (LRA). The requests are a follow-up to responses provided in References 3 and 4. Enclosure 1 contains NextEra's response to the Set 16 request for additional information, revised response to RAI 4.3.1 (Reference 4) and associated changes made to the LRA. For clarity, deleted LRA text is highlighted by strikethroughs and inserted texts highlighted by bold italics.

In Reference 5, NextEra Energy Seabrook provided a response to RAI Follow-up B.2.1.31-4. Based on discussions with the staff during an inspection visit the week of September 26, 2011, NextEra Energy Seabrook is providing clarification to the previous RAI Follow-up B.2.1.31-4 response. Enclosure 2 contains the revised response and changes made to associated commitment number 68.

As noted above, commitment number 68 is revised as a result of changes made in this letter. In Reference 6, NextEra Energy Seabrook provided the First Annual Update to the Seabrook Station License Renewal Application. In Enclosure 1, page 28, of Reference 6, item number 60 identified a change to commitment number 29, however, the associated cover letter incorrectly stated there were no new or revised regulatory commitments. Changes to commitment number 29 and 68 have been reflected in the revised LRA Appendix A - Final Safety Report Supplement Table A.3, License Renewal Commitment List, contained in Enclosure 3 to this letter. There are no other new or revised regulatory commitments contained in this letter.

If there are any questions or additional information is needed, please contact Mr. Richard R. Cliche, License Renewal Project Manager, at (603) 773-7003.

If you have any questions regarding this correspondence, please contact Mr. Michael O'Keefe, Licensing Manager, at (603) 773-7745.

Sincerely,

NextEra Energy Seabrook, LLC.

Paul O. Freeman
Site Vice President

Enclosures:

Enclosure 1- Response to Request for Additional Information Seabrook Station License Renewal Application Set 16, and Associated LRA Changes

Enclosure 2- Revised NextEra Energy Seabrook response to RAI Follow-up B.2.1.31-4 provided in letter SBK-L-11154 dated August 11, 2011

Enclosure 3- LRA Appendix A - Final Safety Report Supplement Table A.3, License Renewal Commitment List, updated to reflect the license renewal commitment changes made in NextEra Seabrook correspondence to date.

cc:

W.M. Dean,	NRC Region I Administrator
G. E. Miller,	NRC Project Manager, Project Directorate I-2
W. J. Raymond,	NRC Resident Inspector
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NEXTera ENERGY SEABROOK

I, Paul O. Freeman, Site Vice President of NextEra Energy Seabrook, LLC hereby affirm that the information and statements contained within are based on facts and circumstances which are true and accurate to the best of my knowledge and belief.

Sworn and Subscribed

Before me this

2nd day of November, 2011

Paul O. Freeman

Site Vice President

Notary Public

SHIRLEY SWEENEY
MY COMMISSION EXPIRES NOV. 18, 2014
NOTARY PUBLIC
NEW HAMPSHIRE

Enclosure 1 to SBK-L-11207

Response to Request for Additional Information
Seabrook Station License Renewal Application
Set 16 and Associated LRA Changes

Request for Additional Information (RAI) Follow-up 3.1.1.60-02:

Background

By letter dated January 5, 2011, the staff issued two requests for additional information (RAIs) to the applicant, RAI 3.1.1-60-01 and RAI 3.1.1-60-02.

In its response to these RAIs dated February 3, 2011, the applicant stated that its design is unique in that the flux thimble tube is a double walled concentric tube design with a capped inner tube and does not provide a pressure boundary function. During its review of the applicant's response, the staff noted that the applicant has the option to place the movable incore detectors back in service and questioned the exclusion of the flux thimble tube as a pressure boundary. A follow-up RAI 3.1.1-60-01/02 was asked on March 30, 2011. In its response dated April 22, 2011, the applicant provided additional bases for not including the flux thimbles as part of its reactor coolant system (RCS) pressure boundary.

Issue

Following its review of the applicant's responses to the RAIs, the staff seeks clarification as to where exactly the RCS pressure boundary is for the applicant's replacement detector assemblies and the original capped detector assemblies.

Request

Verify the RCS pressure boundaries for the replacement and original capped incore detector assemblies. Specifically, identify components that constitute the RCS pressure boundary from the reactor vessel penetration to the seal table and any extensions beyond the seal table. Provide AMR items for the components which are in scope of license renewal in accordance with 10 CFR 54.4(a) and subject to an aging management review and any applicable aging management program(s).

NextEra Energy Seabrook Response

Each incore detector assembly consists of an incore instrument guide tube which houses a flux thimble tube. This flux thimble tube, in turn, houses the fixed incore detectors, a core exit thermocouple and, in the case of the original assembly design, a calibration tube. The incore instrument guide tubes are welded to the reactor vessel bottom instrument penetrations and continue up through the seal table to a high pressure instrument connection.

With the original incore detector assembly design, the incore instrument guide tube and flux thimble tube terminate at the high pressure instrument connection but the calibration tube extends above this connection to provide a pathway for movable incore detectors. These movable incore detectors are no longer utilized and the calibration tube end is capped. The RCS pressure boundary for the original design consists of the reactor vessel

bottom instrument penetration, the incore instrument guide tube, the high pressure instrument connection, the portion of the calibration tube that extends above the high pressure instrument connection, and the pressure retaining cap.

The replacement incore detector assembly design replaces the calibration tube with a solid Inconel 600 rod that does not extend beyond the high pressure instrument connection. The pressure retaining cap is no longer required, and the RCS pressure boundary consists of the reactor vessel bottom instrument penetration, the incore instrument guide tube, and the high pressure instrument connection only.

The above items are located in the LRA as noted below.

- High Pressure Instrument Connection and Cap for Calibration Tube - Listed under component type "Piping and Fittings" on Table 3.1.2-1, line items 3, 4, and 5 on page 3.1-48.

- Reactor Vessel Bottom Instrument Penetrations – Listed under component type "Reactor Vessel Bottom Instrument Tube" on Table 3.1.2-2, line items 3, 4, 5 and 6 on page 3.1-71 and line item 1 on page 3.1-72.

- Incore Instrument Guide Tube – Listed under component type "Incore Instrument Guide Tube" on Table 3.1.2-1, line items 3, 4, and 5 on pages 3.1-46 and line item 1 on page 3.1-471.

- Calibration Tube – As part of the response to this RAI, new line items are added under component type "Calibration Tube" to Table 3.1.2-1, on page 3.1-44, after component type "Bolting (Class 1)".

Based on the above discussion the LRA is changed as follows:

1) On Page 2.3-5, the boundary description for PID-1-RC-20845 is revised as follows:

   PID-1-RC-LR20845:

   The Reactor Coolant System scoping boundary includes the Reactor Vessel head vent piping from the vessel head nozzle to the Pressurizer Relief Tank.

   The scoping boundary includes the Reactor Vessel Level Instrumentation System (RVLIS) line beginning at the restricting orifice located at the upper head penetration and on to the reference leg instrument, to capillary tubing through a containment penetration, and termination at a level transmitter. ~~The sensing line for RVLIS begins at the lower head instrumentation nozzle-to-guide tube weld, passes through the seal table, and terminates at the level devices. The boundary continues from the level device via capillary lines to the containment penetration, and terminates at both level and pressure transmitters. Also included in the boundary are the incore instrument guide tubes.~~

   The scoping boundary also includes fifty eight incore instrument guide tubes welded to individual reactor vessel bottom instrument penetrations. Each incore

instrument guide tube terminates above the seal table at a high pressure instrument connection seal. From two of the Incore Instrument Guide Tubes, a sensing line is provided for RVLIS which terminates at the level devices. The scoping boundary continues from the level device via capillary lines to the containment penetration, and terminates at both level and pressure transmitters.

The incore instrument guide tubes contain a flux thimble tube which runs from inside the reactor vessel to the seal table at the high pressure instrument connection. A high pressure seal is utilized where the instrument cabling exits the guide tube. The flux thimble tube contains fixed incore detectors and core exit thermocouples. The original incore detector assembly flux thimble tubes also contain a flux thimble calibration tube ("calibration tube") that was designed to provide a pathway for movable incore detectors. These movable incore detectors are no longer utilized. The movable flux detector drive system is in a laid-up condition and the calibration tube end is capped to form a RCS pressure boundary. The scoping boundary extends beyond the incore instrument guide tube to include the high pressure instrument connection, the portion of the calibration tube that extends above the high pressure instrument connection and associated cap.

The replacement incore detector assembly thimble tubes (5 out of 58) are not capped as they have a solid Inconel 600 rod in place of the calibration tube. This design eliminates the need for the terminating pressure retaining cap and the RCS pressure boundary extends only to the high pressure seal. The portions of the new incore detector assemblies that are part of the RCS pressure boundary are Safety Class 1 and conform to ASME Section III, Class 1, requirements.

The drain lines from the inner and outer head flange O-ring seals begin at the vessel nozzles welds, through pipes and valve terminating at the Reactor Coolant drain tank.

2) On Table, 3.1.1, on page 3.1-41, line item 3.1.1-85 is revised as follows:

3.1.1-85	Nickel alloy piping, piping components, and piping elements exposed to air-indoor uncontrolled (external)	None	None	NA - No AEM or AMP	Consistent with NUREG-1801. Nickel alloy components exposed to air-indoor uncontrolled (external) are contained in the Reactor Coolant system, Reactor Vessel, Reactor Vessel Internals, and Steam Generator. ***Components having the same internal/external environments have the same aging effects on both internal/external surfaces. As shown in NUREG-1801 Vol. 2 line item IV.E-1 Nickel Alloy in an indoor uncontrolled air (External) environment exhibits no aging effect and that the component or structure will therefore remain capable of performing its intended functions consistent with the CLB for the period of extended operation.***

3) On page 3.1-44, added line items 3, 4, and 5 for the calibration tubes:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG 1801 Vol. 2 Item	Table 3.X.1 Item	Note
Bolting (Class 1)	Pressure Boundary	Steel	Air With Reactor Coolant Leakage (External)	Loss of Preload	Bolting Integrity Program	IV.C2-8 (R-12)	3.1.1-52	A
Bolting (Class 1)	Pressure Boundary	Steel	System Temperature up to 340°C (644°F)	Cumulative Fatigue Damage	TLAA	IV.C2-10 (R-18)	3.1.1-7	A
Calibration Tube	***Pressure Boundary***	***Nickel Alloy***	***Air-Indoor Uncontrolled (External)***	***None***	***None***	***IV.E-1 (RP-03)***	***3.1.1-85***	***A***
Calibration Tube	***Pressure Boundary***	***Nickel Alloy***	***Air With Borated Water Leakage (External)***	***None***	***None***	***None***	***None***	***G, 1***
Calibration Tube	***Pressure Boundary***	***Nickel Alloy***	***Air-Indoor Uncontrolled (Internal)***	***None***	***None***	***IV.E-1 (RP-03)***	***3.1.1-85***	***A, 5***
Flexible Hose	Leakage Boundary (Spatial) Pressure Boundary	Stainless Steel	Air-Indoor Uncontrolled (External)	None	None	IV.E-2 (RP-04)	3.1.1-86	A
Flexible Hose	Leakage Boundary (Spatial) Pressure Boundary	Stainless Steel	Air With Borated Water Leakage (External)	None	None	IV.E-3 (RP-05)	3.1.1-86	A

4) Add a new plant specific note 5 as follows on Page 3.1-69 (note: 4 was added in SBK-L-11123, dated June 2, 2011, in response to RAI 3.2.2.2.4.2-1A).

5. Components having the same internal/external environments have the same aging effects on both internal/external surfaces. As shown in NUREG-1801 Vol. 2 line item IV.E-1, Nickel Alloy in an indoor uncontrolled air (External) environment exhibits no aging effect and the component or structure will therefore, remain capable of performing its intended functions consistent with the CLB for the period of extended operation.

Request for Additional Information (RAI) Follow-up 4.3-1c:

Background

By letter dated April 22, 2011, the applicant responded to RAI 4.3-1b stating that the pressure boundary portion of the American Society of Mechanical Engineers (ASME) Class 1 valves were designed, analyzed, and qualified for service (including fatigue) in accordance with the rules of ASME Code Section III Subsection NB-3500. Updated final safety analysis report (UFSAR) Table 5.2-1 identifies the code edition and addenda applicable to the design of the following types of Class 1 valves: pressurizer safety valves, motor-operated valves, manual valves, control valves, and pressurizer spray valves in the reactor coolant systems. UFSAR Table 5.4-13 also identifies the valves that are included in the reactor coolant pressure boundary.

Issue

The staff noted that, in the 1971 and later editions of the ASME Section III Code, paragraphs NB-3545.3 and NB-3550 required fatigue analyses for valves that have an inlet piping connection larger than 4 inches nominal pipe size unless the exemption requirements of NB 3222.4(d) are met. It is not clear to the staff if the fatigue analyses for all Class 1 valves, has been dispositioned as time-limited aging analysis (TLAA) in accordance with 10 CFR 54.21(c)(1).

Request

- If fatigue analysis were performed for Class 1 valves that have an inlet piping connection larger than 4 inches nominal pipe size as part of the design-basis, amend the license renewal application (LRA) to provide and justify the TLAA disposition for these analyses. Or justify that the fatigue analyses for these Class 1 valves need not to be identified as a TLAA in accordance with 10 CFR 54.21 (c)(1).

- If fatigue analyses were not performed for any Class 1 valves that have an inlet piping connection larger than 4 inches nominal pipe size, amend the LRA to identify these valves. Justify why fatigue analyses were not required for these Class 1 valves in accordance with the ASME Section III Code or the ASME Draft Pump and Valve Code, with reference to the applicable sections of the design code.

NextEra Energy Seabrook Response

A fatigue analysis was performed for Class 1 valves that have an inlet piping connection larger than 4 inches nominal pipe size as part of the original design in accordance to ASME NB-3500. Fatigue analyses of Class 1 valves are considered a TLAA as part of the fatigue analyses of NSSS components discussed in LRA Section 4.3.1 and were

validated under 10 CFR 54.21 (c)(1)(i) as the 40-year design transients bound the numbers of cycles projected to occur during 60 years of plant operations at Seabrook Station. Therefore, the NSSS Class 1 fatigue analyses that are based upon the 40-year design transients remain valid for the period of extended operation. (Reference LRA page 4.3-11)

1) To clarify that the fatigue analysis of Class 1 valves constitute a TLAA, LRA section 4.3.1 as shown on page 4.3-2 is amended as follows:

Summary Description

Nuclear Steam Supply System (NSSS) pressure vessels and primary components, ***including Class 1 valves and piping*** for Seabrook Station were designed in accordance with ASME Section III, Class 1 requirements and are required to have explicit analyses of cumulative fatigue usage. Table 4.3.1-1 identifies the applicable design codes for these components.

2) In addition Table 4.3.1-1 as shown on page 4.3-3 is amended as follows:

Table 4.3.1-1
Original Design Codes for NSSS Components at Seabrook Station

Component	Codes	Edition/Addendum
Reactor Vessel	ASME Section III, Class 1	1971 with Addenda through Summer 1972
Reactor Vessel Closure Head	ASME Section III, Class 1	1971 with Addenda through Summer 1972
Pressurizer	ASME Section III, Class 1	1971 with Addenda through Summer 1972
Steam Generators	ASME Section III, Class 1	1971 with Addenda through Summer 1972
Reactor Coolant Pump Casings	ASME Section III, Class 1	1971 with Addenda through Summer 1972
Reactor Coolant Class 1 Valves	***ASME Section III, Class 1***	***1974 with Addenda through Winter 1975***
Reactor Coolant Class 1 Piping	***ASME Section III, Class 1***	***1971 with Addenda through Summer 1972***

3) In addition in NextEra's response to RAI 4.3-1 contained in letter SBK-L-11015 dated February 3, 2011 previously stated *"A search by NextEra Energy Seabrook did not find any Class 1 valves with separately computed cumulative usage factors since the original stress and fatigue analysis was performed."* Since this response was submitted NextEra has identified the specific analysis performed for Class 1 piping and valves. The response previously submitted in SBK-L-11015 Enclosure 2, page 8

of 47 is revised as follows and Table 1 is replaced in its entirety as follows:

Revised Response to RAI 4.3.1 provided in SBK-L-11015; Enclosure 2

The original design basis 40-yr CUF values for all components and/or critical locations that are applicable to the dispositions in LRA Sections 4.3.1, 4.3.2, and 4.3.3 are provided in Table 1.

Evaluation of ASME Class 1 valves, that have an inlet piping connection larger than 4 inches, was considered in the original stress and fatigue analyses as part of the original design of Seabrook Station in accordance to ASME NB-3500.

~~Evaluation of ASME Class 1 valves was considered in the original stress and fatigue analyses of the Class 1 piping for Seabrook Station~~. Fatigue conformance **for the Class 1 piping systems containing the valves** ~~of these valves~~ was demonstrated through the performance of **a** fatigue analysis ~~for the piping system containing the valves~~. In the ***piping*** fatigue analyses, allowable moment ranges were developed for all transient loading combinations so that the ASME Section III, Subsection NB-3650, Equation 12 expansion stress requirement is met and CUF is less than 1.0. Then actual computed moment ranges for each line are compared to the allowable moment range for all significant transient combinations (transients which give a usage factor greater than or equal to 0.02) the line can experience. If the calculated moment range is less than the allowable moment range for each transient combination, then the cumulative usage factor is less than 1.0 and Equation 12 is met. The Equation 13 stress range is also computed, and if shown acceptable, fatigue conformance of the analyzed ***piping*** ~~valves~~ is demonstrated. If one or more allowable moment ranges is exceeded by the actual moment range for the given transient conditions, a more detailed fatigue analysis ~~would be~~ ***was*** performed and a unique cumulative usage factor ~~would be~~ ***was*** reported ~~for that valve~~. ~~A search by NextEra Energy Seabrook did not find any Class 1 valves with separately computed cumulative usage factors since the original stress and fatigue analysis was performed. Thus, it can only be stated that the Class 1 valves achieved fatigue usage values less than 1.0 for all analyzed transients.~~

All design-basis plant transients listed in Table 4.3.1-2 were considered in ~~these umbrella~~ ***the*** fatigue analyses in terms of severity and number of occurrences.

Because it has been projected that the ***original*** design-basis number of design transients will not be exceeded during the ~~60-year~~ period of extended operation, analyses for these components will be dispositioned in accordance with 10 CFR 54.21(c)(1)***(i)***.

Table 1: List of Fatigue Usage Values

Component	Location	Design Fatigue Usage
RPV	Outlet Nozzle	0.1077
RPV	Outlet Nozzle Vessel Support Pad	0.0211
RPV	Inlet Nozzle	0.0795
RPV	Inlet Nozzle Vessel Support Pad	0.027
RPV	Head Flange	0.0155
RPV	Vessel Flange	0.0196
RPV	Closure Studs	0.4780
RPV	Vessel Wall Transition	0.0105
RPV	Bottom Head-to-Shell Juncture	0.0070
RPV	CRDM Housings	0.1093
RPV	Bottom Head Instrument Tubes (pos. 1)	0.0014
RPV	Bottom Head Instrument Tubes (pos. 2)	0.3184
RPV	Core Support Lugs	0.0627
RPV	Head Adapter Lugs	0.0036
Internals	Lower Support Columns	0.271
Internals	Core Barrel Nozzle	0.410
Internals	Lower Core Plate	0.0744
Internals	Upper Core Plate	0.183
Pressurizer	Valve Support Bracket	0.102
Pressurizer	Surge Nozzle (Path6A, Inside) (3)	0.6325
Pressurizer	Spray Nozzle (Path8A9) (3)	0.981
Pressurizer	Safety/Relief Nozzle (Pipe) (3)	0.0030
Pressurizer	Lower Head	0.116
Pressurizer	Heater Well	0.128
Pressurizer	Upper Head/Upper Shell	0.906
Pressurizer	Lower Head/Support Skirt	0.736
Pressurizer	Manway	0.875
Pressurizer	Instrument Nozzle	0.166
Pressurizer	Immersion Heater	0.122
Pressurizer	Trunnion/Shell Buildup	0.063
S/G	Divider Plate	0.997
S/G	Tubesheet and Shell Junction	0.846
S/G	Tube to Tubesheet Weld	0.459
S/G	Tubes	0.902
S/G	Main Feedwater Nozzle	0.921
Piping	Pressurizer Surge Line (3)	0.6
Piping	Pressurizer Spray Line (2)	0.990
Piping	Pressurizer Safety and Relief Valve	0.820

Component	Location	Design Fatigue Usage
Piping	Auxiliary Spray Line [3]	0.554
~~Piping~~[4]	~~2-inch Crossover Leg Drain Line~~[4]	~~0.819~~
~~Piping~~[4]	~~2-inch Cold Leg RTD~~[4][3]	~~0.87~~
~~Piping~~[4]	~~1 and 2-inch Hot Leg RTD~~[4][3]	~~0.900~~
~~Piping~~[4]	~~3-inch Crossover Leg RTD~~[4][3]	~~0.870~~
Piping	2-inch Crossover Leg Loop 1, 2, 4 Drain[3]	0.395
Piping	1.5-inch Boron Injection (BIT) Lines[3]	0.990
Piping	10-inch Accumulator Lines [3]	0.900
Piping	6-inch Low Head Safety Injection to Accumulator Lines[3]	0.800
Piping	2-inch High Head Safety Injection to Accumulator Lines[3]	0.800
Piping	6-inch Safety Injection Loop 2[3]	0.125
Piping	6-inch Safety Injection Loop 3[3]	0.330
Piping	12-inch RHR Loop 1 and 4 Suction[3]	0.99
Piping	3-inch Normal (Loop 1) and Alternate (Loop 4) Charging[3]	0.440
Piping	3-inch Normal Letdown[3]	0.990
Nozzle	3/4-inch Bosses (pressure taps, etc.) All Loops	0.81
Nozzle	3/4-inch Hot Leg Sampling Connection	0.98
Nozzle	14-inch Hot Leg Surge Nozzle [1]	0.6
Nozzle	4-inch Cold Leg Pressurizer Spray Nozzles	0.4
Nozzle	2-1/2-inch Hot and Cold Leg Thermowells	0.81
Nozzle	3-inch Cold Leg Loop 1 Normal Charging Nozzle	0.99
Nozzle	3-inch Cold Leg Loop 4 Alternate Charging nozzle	0.99
Nozzle	6-inch SIS Loops 2 and 3 Hot Leg Nozzle	0.01
Nozzle	3-inch Cold Leg (All Loops) Boron Injection Nozzle	0.99
Nozzle	10-inch Cold Leg Accumulator Nozzle (All Loops)	0.95
Nozzle	1-inch Cold Leg Loop 3 Excess Letdown	0.99
Nozzle	3-inch Crossover Leg Normal Letdown Nozzle	0.20
Nozzle	1-inch Hot Leg RTD	0.60
Nozzle	2-inch Cold Leg RTD	0.70
Nozzle	3-inch Crossover Leg Return RTD	0.40
Nozzle	2-inch Crossover Leg Loops 1, 2, 4 Drain	0.116
Nozzle	12-inch Hot Leg RHR Nozzle	0.92
Valve	Pressurizer Spray (Butt Welded)	0.07
Valve	Auxiliary Spray (Socket Welded) (maximum value)	0.554
~~Valve~~[4]	~~RTD Loops 1/2/3 (Socket Welded) (maximum value)~~[4]	~~0.400~~
~~Valve~~[4]	~~RTD Loops 1/2/3 (Butt Welded) (maximum value)~~[4]	~~0.300~~
~~Valve~~[4]	~~RTD Loop 4 (Socket Welded) (maximum value)~~[4]	~~0.800~~
~~Valve~~[4]	~~RTD Loop 4 (Butt Welded) (maximum value)~~[4]	~~0.300~~

Component	Location	Design Fatigue Usage
Valve	RC Drain Line Loops 1/2/3/4 (Socket-Welded)	0.819
Valve	Boron Injection Line Loops 1/2/3/4 (Socket-Welded)	0.85
Valve	Boron Injection Line Loops 1/2/3/4 (Butt-Welded)	0.010
Valve	Accumulator Line Loops 1/2/3/4 (Socket Welded)	0.40
Valve	Accumulator Line Loops 1/2/3/4 (Butt Welded) (maximum value)	0.40
Valve	SI Lines (Hot Leg Recirculation) (Socket Welded)	0.05
Valve	SI Lines (Hot Leg Recirculation) (Butt Welded)	0.09
Valve	RHR Loops 1/4 (Socket Welded)	0.700
Valve	RHR Loops 1/4 (Butt Welded) (maximum value)	0.300
Valve	CVCS Charging Line Loops 1 /4 (Butt Welded) (maximum value)	0.440
Valve	CVCS Normal Letdown Line (Socket Welded)	0.819
Valve	CVCS Normal Letdown Line (Butt Welded) (maximum value)	0.098
Valve	Class 1 Valves > 4 inches	< 1.00

Notes for Table 1:

(1) The highest reported fatigue usage of 0.6 is at the Reactor Coolant Loop Nozzle Transition and Safe End

(2) 6-in x 4-in reducer, the most limiting location in the Pressurizer Spray lines

(3) Usage taken from most limiting location in the corresponding stress report

(4) Component(s) removed via Engineering Change

Enclosure 2 to SBK-L- 11207

Revised NextEra Energy Seabrook response to RAI Follow-up B.2.1.31-4 provided in letter SBK-L-11154 dated August 11, 2011

In NextEra Energy Seabrook, LLC letter SBK-L-11154 (Reference 5), NextEra Energy Seabrook provided a response to RAI Follow-up B.2.1.31-4. Based on discussions with the staff during an inspection visit the week of September 26, 2011, NextEra Energy Seabrook is providing clarification to the previous RAI Follow-up B.2.1.31-4 response. The following revises response to Follow-up RAI B2.1.31-4:

Revised Response to (RAI) Follow-up B.2.1.31-4

1. Seabrook Station does not have continuous borated water leakage from the spent fuel pool. Currently, any leakage from the spent fuel pool collects in a steel catch basin installed in the sump and does not come in contact with concrete.

   NextEra Energy Seabrook commits to confirm the absence of embedded steel corrosion by performing a shallow core sample in an area subjected to wetting of borated water during the time frame of the spent fuel pool leakage. The core samples will be examined for degradation of concrete from borated water and also expose rebar to detect any degradation such as loss of material.

   As demonstrated by examination of concrete cores from the Connecticut Yankee spent fuel pool and Salem Nuclear Generating Station referenced in the "Safety Evaluation Report Related to the License Renewal of Salem Nuclear Generating Station Units 1 and 2" (ADAMS Accession Number ML11164A051), the structural capacity will not be significantly affected by exposure to borated water. In addition, borated water is not in continuous contact with concrete at Seabrook Station. Hence performing a confirmatory core bore and exposing rebar by December 31, 2015 is adequate.

2. Seabrook Station currently performs hydro-lazing of the spent fuel pool leakoff lines at a 4 ½ year frequency and will maintain this throughout the period of extended operation. Leak-off is recorded once a month on a spent fuel pool leakage spread sheet. The System Engineer monitors the leak-off telltale drains via the spread sheet for unusual leakage or lack thereof, which could be an indicator of blockage. Monitoring will continue throughout the period of extended operation.

3. ***The Spent Fuel Pool, Cask Handling and Fuel Transfer canal areas, have nine zones that collect leakage and there are seven sample points. The Spent Fuel Pool, where spent fuel is stored, is separated from the Cask Handling and Fuel Transfer Canal area by a gate. Zones 1, 2, 3 and 4 leak collection zones are under the Spent Fuel Pool area in a quadrant configuration. Each Spent Fuel Pool quadrant has a separate leak collection sample line. There have been no incidents of leakage from the Spent Fuel Pool area. To date, the only incidents of leakage have been from the Cask Handling and Fuel Transfer Canal area. Leak collection Zones 8 and 9 are under the Fuel Transfer Canal, with the north end monitored by Zone 8 and the***

south end by Zone 9. Each Fuel Transfer Canal Zone has a separate leakage collection sample line. Leak collection Zones 5, 6 and 7 are from the cask handling area. Any leakage from cask handling area Zones 5, 6 and 7 are combined into the Zone 6 leakage collection sample line. Zone 6 is the only leakage collection sample line that routinely has water flow. The majority of water in Zone 6 sample line is from groundwater in leakage.

Currently ~~the spent fuel pool~~ leakoff collection is analyzed for gamma and tritium activity monthly. On April 6, 2011, tritium activity concentration measured in ~~Spent Fuel Pool (SFP)~~ ***the Cask Handling area*** zone 6 tell-tale leakage collection pipe indicated a step increase from 2.58E-5 μCi/ml to 7.87E-3 μCi/ml.

Typically the Zone 6 leakoff collection tritium activity concentration is approximately 2 to 9E-05 μCi/mL. The Cask Handling area water tritium activity concentration is 1 E-01 μCi/mL. The Cask Handling area leak rate is determined by a simple calculation, based on ratio of the Cask Handling area water tritium concentration, the Zone 6 leakoff collection sample tritium concentration and the Zone 6 leakoff water flow rate.

The increased leak rate ***in the Spring of 2011*** occurred coincident with refilling of the cask ***handling area*** ~~loading~~ pool which had previously been drained to support maintenance and testing of the spent fuel transfer system equipment. The ***Zone 6 leakoff sample*** tritium activity concentration increased by about a factor of 300 and the calculated ~~pool~~ ***Cask Handling area*** leak rate was 1.2 gpd. Subsequent measurements identified the leak rate peaked at approximately 2.57 gpd on 4/10/2011, after which leakage decreased to the current level of 0.016 gpd (approximately 2oz. per day) by 5/9/2011.

On average, about 10 gallons per day of groundwater leaks out of the zone 6 ~~tell-tale~~ ***leakoff*** collection pipe. This groundwater has background contamination from tritium that is diffusing out of the concrete that was originally contaminated from ~~the pool~~ ***Cask Handling and Fuel Transfer Canal area*** leakage identified in 1999. That leakage was terminated in 2004 with the application of the first non-metallic liner. Groundwater leakage is monitored by the Structures Monitoring Program.

~~Fuel pool volumetric leakage is estimated by taking the ratio of the leak-off line tritium concentration to the pool tritium concentration and multiplying that value by the amount of zone 6 leakage pumped out from the collection tank. In this particular instance, the only leak-off line that indicated any leakage was zone 6.~~

There are several potential causes for the increased leakage, and each is discussed below. Those include:

- A new SS liner plate leak in an area not lined with the non-metallic liner.
- A failure in the new non-metallic liner at the same location as a SS liner failure.

- A skimmer pit leak

Corrective actions are being implemented and are on going, such as:

- Determining if the skimmer pit(s) are the source of the current leakage.
- Verifying integrity of cask loading area non-metallic liner through drain down and inspection.
- Revising procedures for cask filling to limit pool level.
- Revising the maintenance work order for removal sequence of the weir gate, or reduce the height of the weir gate.
- Determining whether the current design of skimmer pits is appropriate and what changes need to be made to prevent leakage out of the pit.
- Perform a qualified visual inspection of the weld at the skimmer plate to discharge line interface to determine whether there is actually a seal weld.

The above corrective actions are scheduled to be completed by ~~12/31/2011~~ ***5/31/2012***.

As explained in response #2, the leakoff lines are hydro-lazed every 4 ½ years and the System Engineer monitor's the leak-off telltale drains via a collection spread sheet for unusual leakage conditions.

Currently ~~the spent fuel pool~~ leakoff collection is analyzed for gamma and tritium monthly. The program will be enhanced to perform sampling for chlorides, sulfates, pH and iron ~~for four quarters (for seasonal variations) of one year once every 5 years~~ ***every three months. These samples will be trended and reviewed once every five years for signs of concrete degradation (as reported in LRA section 3.5.2.2.1.1 groundwater sample are in the aggressive range). The effects of the groundwater and concrete degradation are presently being monitored by the Seabrook Station Engineering Staff.*** Information from these samples will be incorporated into the Structures Monitoring Program assessments.

Based on the above discussion, the following changes are made to the LRA:

1) License Renewal Application Appendix B, Section B.2.1.31, page B-169, is revised to add Enhancement 1d and 3 as follows:

   1.

   d Perform a confirmatory core bore and expose rebar in an area under the catch basin in spent fuel pool leakage sump.

   3. Enhance procedure to perform chemistry sample of the ~~spent fuel pool~~ leakoff collection points.

a. Procedure CP 3.1, "Primary Chemistry Control Program" will be enhanced to include chemistry sampling of the ~~spent fuel pool~~ leakoff collection points for chlorides, sulfates, pH and iron ~~for four quarters of one year once every 5 years~~ once every three months.

2) License Renewal Application Appendix A, Section A.3, , is revised to add commitments as follows:

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
67	Structures Monitoring Program	Perform one shallow core bore in an area that was continuously wetted from borated water to be examined for concrete degradation and also expose rebar to detect any degradation such as loss of material.	A.2.1.31	No later than December 31, 2015
68	Structures Monitoring Program	Perform sampling at the ~~spent fuel pool~~ leakoff collection points for chlorides, sulfates, pH and iron ~~for four quarters of one year once every 5 years~~ ***once every three months.***	A.2.1.31	Starting January 2014

Enclosure 3 to SBK-L-11207

LRA Appendix A - Final Safety Report Supplement

Table A.3 License Renewal Commitment List

A.3 LICENSE RENEWAL COMMITMENT LIST

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
1.	PWR Vessel Internals	An inspection plan for Reactor Vessel Internals will be submitted for NRC review and approval.	A.2.1.7	Program to be implemented prior to the period of extended operation. Inspection plan to be submitted to NRC not later than 2 years after receipt of the renewed license or not less than 24 months prior to the period of extended operation, whichever comes first.
2.	Closed-Cycle Cooling Water	Enhance the program to include visual inspection for cracking, loss of material and fouling when the in-scope systems are opened for maintenance.	A.2.1.12	Prior to the period of extended operation
3.	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Enhance the program to monitor general corrosion on the crane and trolley structural components and the effects of wear on the rails in the rail system.	A.2.1.13	Prior to the period of extended operation
4.	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Enhance the program to list additional cranes for monitoring.	A.2.1.13	Prior to the period of extended operation
5.	Compressed Air Monitoring	Enhance the program to include an annual air quality test requirement for the Diesel Generator compressed air sub system.	A.2.1.14	Prior to the period of extended operation
6.	Fire Protection	Enhance the program to perform visual inspection of penetration seals by a fire protection qualified inspector.	A.2.1.15	Prior to the period of extended operation.

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
7.	Fire Protection	Enhance the program to add inspection requirements such as spalling, and loss of material caused by freeze-thaw, chemical attack, and reaction with aggregates by qualified inspector.	A.2.1.15	Prior to the period of extended operation.
8.	Fire Protection	Enhance the program to include the performance of visual inspection of fire-rated doors by a fire protection qualified inspector.	A.2.1.15	Prior to the period of extended operation.
9.	Fire Water System	Enhance the program to include NFPA 25 guidance for "where sprinklers have been in place for 50 years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory for field service testing".	A.2.1.16	Prior to the period of extended operation.
10.	Fire Water System	Enhance the program to include the performance of periodic flow testing of the fire water system in accordance with the guidance of NFPA 25.	A.2.1.16	Prior to the period of extended operation.
11.	Fire Water System	Enhance the program to include the performance of periodic visual or volumetric inspection of the internal surface of the fire protection system upon each entry to the system for routine or corrective maintenance. These inspections will be documented and trended to determine if a representative number of inspections have been performed prior to the period of extended operation. If a representative number of inspections have not been performed prior to the period of extended operation, focused inspections will be conducted. These inspections will be performed within ten years prior to the period of extended operation.	A.2.1.16	Within ten years prior to the period of extended operation.
12.	Aboveground Steel Tanks	Enhance the program to include components and aging effects required by the Aboveground Steel Tanks.	A.2.1.17	Prior to the period of extended operation.
13.	Aboveground Steel Tanks	Enhance the program to include an ultrasonic inspection and evaluation of the internal bottom surface of the two Fire Protection Water Storage Tanks.	A.2.1.17	Within ten years prior to the period of extended operation.

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
14.	Fuel Oil Chemistry	Enhance program to add requirements to 1) sample and analyze new fuel deliveries for biodiesel prior to offloading to the Auxiliary Boiler fuel oil storage tank and 2) periodically sample stored fuel in the Auxiliary Boiler fuel oil storage tank.	A.2.1.18	Prior to the period of extended operation.
15.	Fuel Oil Chemistry	Enhance the program to add requirements to check for the presence of water in the Auxiliary Boiler fuel oil storage tank at least once per quarter and to remove water as necessary.	A.2.1.18	Prior to the period of extended operation.
16.	Fuel Oil Chemistry	Enhance the program to require draining, cleaning and inspection of the diesel fire pump fuel oil day tanks on a frequency of at least once every ten years.	A.2.1.18	Prior to the period of extended operation.
17.	Fuel Oil Chemistry	Enhance the program to require ultrasonic thickness measurement of the tank bottom during the 10-year draining, cleaning and inspection of the Diesel Generator fuel oil storage tanks, Diesel Generator fuel oil day tanks, diesel fire pump fuel oil day tanks and auxiliary boiler fuel oil storage tank.	A.2.1.18	Prior to the period of extended operation.
18.	Reactor Vessel Surveillance	Enhance the program to specify that all pulled and tested capsules, unless discarded before August 31, 2000, are placed in storage.	A.2.1.19	Prior to the period of extended operation.
19.	Reactor Vessel Surveillance	Enhance the program to specify that if plant operations exceed the limitations or bounds defined by the Reactor Vessel Surveillance Program, such as operating at a lower cold leg temperature or higher fluence, the impact of plant operation changes on the extent of Reactor Vessel embrittlement will be evaluated and the NRC will be notified.	A.2.1.19	Prior to the period of extended operation.

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
20.	Reactor Vessel Surveillance	Enhance the program as necessary to ensure the appropriate withdrawal schedule for capsules remaining in the vessel such that one capsule will be withdrawn at an outage in which the capsule receives a neutron fluence that meets the schedule requirements of 10 CFR 50 Appendix H and ASTM E185-82 and that bounds the 60-year fluence, and the remaining capsule(s) will be removed from the vessel unless determined to provide meaningful metallurgical data.	A.2.1.19	Prior to the period of extended operation.
21.	Reactor Vessel Surveillance	Enhance the program to ensure that any capsule removed, without the intent to test it, is stored in a manner which maintains it in a condition which would permit its future use, including during the period of extended operation.	A.2.1.19	Prior to the period of extended operation.
22.	One-Time Inspection	Implement the One Time Inspection Program.	A.2.1.20	Within ten years prior to the period of extended operation.
23.	Selective Leaching of Materials	Implement the Selective Leaching of Materials Program. The program will include a one-time inspection of selected components where selective leaching has not been identified and periodic inspections of selected components where selective leaching has been identified.	A.2.1.21	Within five years prior to the period of extended operation.
24.	Buried Piping And Tanks Inspection	Implement the Buried Piping And Tanks Inspection Program.	A.2.1.22	Within ten years prior to entering the period of extended operation
25.	One-Time Inspection of ASME Code Class 1 Small Bore-Piping	Implement the One-Time Inspection of ASME Code Class 1 Small Bore-Piping Program.	A.2.1.23	Within ten years prior to the period of extended operation.
26.	External Surfaces Monitoring	Enhance the program to specifically address the scope of the program, relevant degradation mechanisms and effects of interest, the refueling outage inspection frequency, the inspections of opportunity for possible corrosion under insulation, the training requirements for inspectors and the required periodic reviews to determine program effectiveness.	A.2.1.24	Prior to the period of extended operation.

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
27.	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Implement the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program.	A.2.1.25	Prior to the period of extended operation.
28.	Lubricating Oil Analysis	Enhance the program to add required equipment, lube oil analysis required, sampling frequency, and periodic oil changes.	A.2.1.26	Prior to the period of extended operation.
29.	Lubricating Oil Analysis	Enhance the program to sample the oil for the ~~Switchyard SF_6 compressors and the~~ Reactor Coolant pump oil collection tanks.	A.2.1.26	Prior to the period of extended operation.
30.	Lubricating Oil Analysis	Enhance the program to require the performance of a one-time ultrasonic thickness measurement of the lower portion of the Reactor Coolant pump oil collection tanks prior to the period of extended operation.	A.2.1.26	Prior to the period of extended operation.
31.	ASME Section XI, Subsection IWL	Enhance procedure to include the definition of "Responsible Engineer".	A.2.1.28	Prior to the period of extended operation.
32.	Structures Monitoring Program	Enhance procedure to add the aging effects, additional locations, inspection frequency and ultrasonic test requirements.	A.2.1.31	Prior to the period of extended operation.
33.	Structures Monitoring Program	Enhance procedure to include inspection of opportunity when planning excavation work that would expose inaccessible concrete.	A.2.1.31	Prior to the period of extended operation.

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
34.	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Implement the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program.	A.2.1.32	Prior to the period of extended operation.
35.	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Implement the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program.	A.2.1.33	Prior to the period of extended operation.
36.	Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Implement the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program.	A.2.1.34	Prior to the period of extended operation.
37.	Metal Enclosed Bus	Implement the Metal Enclosed Bus program.	A.2.1.35	Prior to the period of extended operation.
38.	Fuse Holders	Implement the Fuse Holders program.	A.2.1.36	Prior to the period of extended operation.
39.	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Implement the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program.	A.2.1.37	Prior to the period of extended operation.
40.	345 KV SF_6 Bus	Implement the 345 KV SF_6 Bus program.	A.2.2.1	Prior to the period of extended operation.

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
41.	Metal Fatigue of Reactor Coolant Pressure Boundary	Enhance the program to include additional transients beyond those defined in the Technical Specifications and UFSAR.	A.2.3.1	Prior to the period of extended operation.
42.	Metal Fatigue of Reactor Coolant Pressure Boundary	Enhance the program to implement a software program, to count transients to monitor cumulative usage on selected components.	A.2.3.1	Prior to the period of extended operation.
43.	Pressure – Temperature Limits, including Low Temperature Overpressure Protection Limits	Seabrook Station will submit updates to the P-T curves and LTOP limits to the NRC at the appropriate time to comply with 10 CFR 50 Appendix G.	A.2.4.1.4	The updated analyses will be submitted at the appropriate time to comply with 10 CFR 50 Appendix G, Fracture Toughness Requirements.
44.	Environmentally-Assisted Fatigue Analyses (TLAA)	NextEra Seabrook will perform a review of design basis ASME Class 1 component fatigue evaluations to determine whether the NUREG/CR-6260-based components that have been evaluated for the effects of the reactor coolant environment on fatigue usage are the limiting components for the Seabrook plant configuration. If more limiting components are identified, the most limiting component will be evaluated for the effects of the reactor coolant environment on fatigue usage. If the limiting location identified consists of nickel alloy, the environmentally-assisted fatigue calculation for nickel alloy will be performed using the rules of NUREG/CR-6909. (1) Consistent with the Metal Fatigue of Reactor Coolant Pressure Boundary Program Seabrook Station will update the fatigue usage calculations using refined fatigue analyses, if necessary, to determine acceptable CUFs (i.e., less than 1.0) when accounting for the effects of the reactor water environment. This includes applying the appropriate F_{en} factors to valid CUFs determined from an existing fatigue analysis valid for the period of extended operation or from an analysis using an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case). (2) If acceptable CUFs cannot be demonstrated for all the selected locations, then additional plant-specific locations will be evaluated. For the additional plant-specific locations, if CUF,	A.2.4.2.3	At least two years prior to entering the period of extended operation.

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
		including environmental effects is greater than 1.0, then Corrective Actions will be initiated, in accordance with the Metal Fatigue of Reactor Coolant Pressure Boundary Program, B.2.3.1. Corrective Actions will include inspection, repair, or replacement of the affected locations before exceeding a CUF of 1.0 or the effects of fatigue will be managed by an inspection program that has been reviewed and approved by the NRC (e.g., periodic non-destructive examination of the affected locations at inspection intervals to be determined by a method accepted by the NRC).		
45.	Number Not Used			
46.	Protective Coating Monitoring and Maintenance	Enhance the program by designating and qualifying an Inspector Coordinator and an Inspection Results Evaluator.	A.2.1.38	Prior to the period of extended operation
47.	Protective Coating Monitoring and Maintenance	Enhance the program by including, "Instruments and Equipment needed for inspection may include, but not be limited to, flashlight, spotlights, marker pen, mirror, measuring tape, magnifier, binoculars, camera with or without wide angle lens, and self sealing polyethylene sample bags."	A.2.1.38	Prior to the period of extended operation
48.	Protective Coating Monitoring and Maintenance	Enhance the program to include a review of the previous two monitoring reports.	A.2.1.38	Prior to the period of extended operation
49.	Protective Coating Monitoring and Maintenance	Enhance the program to require that the inspection report is to be evaluated by the responsible evaluation personnel, who is to prepare a summary of findings and recommendations for future surveillance or repair.	A.2.1.38	Prior to the period of extended operation
50.	ASME Section XI, Subsection IWE	Perform UT testing of the containment liner plate in the vicinity of the moisture barrier for loss of material.	A.2.1.27	Within the next two refueling outages, OR15 or OR16, and repeated at intervals of no more than five refueling outages
51.	Number Not Used			

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
52.	ASME Section XI, Subsection IWL	Implement measures to maintain the exterior surface of the Containment Structure, from elevation -30 feet to +20 feet, in a dewatered state.	A.2.1.28	By 2013
53.	Reactor Head Closure Studs	Replace the spare reactor head closure stud(s) manufactured from the bar that has a yield strength > 150 ksi with ones that do not exceed 150 ksi.	A.2.1.3	Prior to the period of extended operation.
54.	Steam Generator Tube Integrity	Unless an alternate repair criteria changing the ASME code boundary is permanently approved by the NRC, or the Seabrook Station steam generators are changed to eliminate PWSCC-susceptible tube-to-tubesheet welds, submit a plant-specific aging management program to manage the potential aging effect of cracking due to PWSCC at least twenty-four months prior to entering the Period of Extended Operation.	A.2.1.10	Program to be submitted to NRC at least 24 months prior to the period of extended operation.
55.	Steam Generator Tube Integrity	Seabrook will perform an inspection of each steam generator to assess the condition of the divider plate assembly.	A.2.1.10	Prior to entering the period of extended operation
56.	Closed-Cycle Cooling Water System	Revise the station program documents to reflect the EPRI Guideline operating ranges and Action Level values for hydrazine and sulfates.	A.2.1.12	Prior to entering the period of extended operation.
57.	Closed-Cycle Cooling Water System	Revise the station program documents to reflect the EPRI Guideline operating ranges and Action Level values for Diesel Generator Cooling Water Jacket pH.	A.2.1.12	Prior to entering the period of extended operation.
58.	Fuel Oil Chemistry	Update Technical Requirement Program 5.1, (Diesel Fuel Oil Testing Program) ASTM standards to ASTM D2709-96 and ASTM D4057-95 required by the GALL XI.M30 Rev 1	A.2.1.18	Prior to the period of extended operation.
59.	Nickel Alloy Nozzles and Penetrations	The Nickel Alloy Aging Nozzles and Penetrations program will implement applicable Bulletins, Generic Letters, and staff accepted industry guidelines.	A.2.2.3	Prior to the period of extended operation.
60.	Buried Piping and Tanks Inspection	Implement the design change replacing the buried Auxiliary Boiler supply piping with a pipe-within-pipe configuration with leak indication capability.	A.2.1.22	Prior to entering the period of extended operation.
61.	Compressed Air Monitoring Program	Replace the flexible hoses associated with the Diesel Generator air compressors on a frequency of every 10 years.	A.2.1.14	Within ten years prior to entering the period of extended operation.
62.	Water Chemistry	Enhance the program to include a statement that sampling frequencies are increased when chemistry action levels are exceeded.	A.2.1.2	Prior to entering the period of extended operation.

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
63.	Flow Induced Erosion	Ensure that the quarterly CVCS Charging Pump testing is continued during the PEO. Additionally, add a precaution to the test procedure to state that an increase in the CVCS Charging Pump mini flow above the acceptance criteria may be indicative of erosion of the mini flow orifice as described in LER 50-275/94-023.	N/A	Prior to the period of extended operation
64.	Buried Piping and Tanks Inspection	Soil analysis shall be performed prior to entering the period of extended operation to determine the corrosivity of the soil in the vicinity of non-cathodically protected steel pipe within the scope of this program. If the initial analysis shows the soil to be non-corrosive, this analysis will be re-performed every ten years thereafter.	A.2.1.22	Prior to entering the period of extended operation.
65.	Flux Thimble Tube	Implement measures to ensure that the movable incore detectors are not returned to service during the period of extended operation.	N/A	Prior to entering the period of extended operation
66.	Operating Experience Reviews	Enhance the current station operating experience review process implemented in response to NUREG 0737 Task I.C.5 Procedures for Feedback of Operating Experience to Plant Staff (UFSAR □1.9.1) to include future reviews of plant-specific and industry operating experience in order to confirm the effectiveness of the license renewal aging management programs and to determine the need for programs to be enhanced or the need to develop new aging management programs.	N/A	Within ten years prior to entering the period of extended operation.
67.	Structures Monitoring Program	Perform one shallow core bore in an area that was continuously wetted from borated water to be examined for concrete degradation and also expose rebar to detect any degradation such as loss of material.	A.2.1.31	No later than December 31, 2015
68.	Structures Monitoring Program	Perform sampling at the ~~spent fuel pool~~ leakoff collection point**s** for chlorides, sulfates, pH and iron ~~for four quarters of one year once every 5 years~~ ***once every three months.***	A.2.1.31	Starting January 2014