NEXTera ENERGY SEABROOK

July 2, 2013

SBK-L-13115

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

Seabrook Station
Third Annual Update to the
NextEra Energy Seabrook License Renewal Application

References:

1. NextEra Energy Seabrook, LLC letter SBK-L-10077, "Seabrook Station Application for Renewed Operating License", May 25, 2010. (Accession Number ML101590099)
2. NextEra Energy Seabrook, LLC letter SBK-L-11773, "First Annual Update to the Seabrook License Renewal Application", August 25, 2011. (Accession Number ML11241A142)
3. NextEra Energy Seabrook, LLC letter SBK-L-12186, "Second Annual Update to the Seabrook License Renewal Application", September 18, 2012. (Accession Number ML12268A171)
4. LR-ISG-2011-03: Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program XI.M41, "Buried and Underground Piping and Tanks", July, 2012. (Accession Number ML12138A295)
5. LR-ISG-LR-ISG-2012-01: Wall Thinning Due To Erosion Mechanisms, April, 2013. (Accession Number ML12352A058)
6. NextEra Energy Seabrook, LLC letter SBK-L-13084, "Revised Response to RAI B.2.1.3-5 and RAI 4.7.2-1", May 8, 2013. (Accession Number ML13135A005)
7. NextEra Energy Seabrook, LLC letter SBK-L-12183, "Response to Request for Additional Information-Set 18 Operating Experience", September 18, 2012. (Accession Number ML12268A170)
8. NextEra Energy Seabrook, LLC letter SBK-L-11015, "Response to Request for Additional Information, NextEra Energy Seabrook License Renewal Application, Sets 6, 7 and 8", February 3, 2011. (Accession Number ML110380081)
9. NextEra Energy Seabrook, LLC letter SBK-L-11069, "Response to Request for Additional Information, NextEra Energy Seabrook License Renewal Application, Request for Additional Information - Set 12", April 22, 2011. (Accession Number ML11115A116)

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10. NextEra Energy Seabrook, LLC letter SBK-L-11207, "Response to Request for Additional Information, NextEra Energy Seabrook License Renewal Application, Request for Additional Information - Set 16", November 2, 2011. (Accession Number ML11308A025)

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.

The License Renewal Rule, 10 CFR 54.21(b) requires that each year following submittal of a license renewal application (LRA), and at least 3 months before scheduled completion of the NRC review, an update to the license renewal application must be submitted that identifies any change to the current licensing basis (CLB) of the facility that materially affects the content of the LRA including the FSAR supplement.

In accordance with the License Renewal Rule, NextEra Energy Seabrook, LLC has performed a third annual review of CLB changes since the submittal of Reference 1, to determine whether any sections of the LRA were affected by these changes. A review has also been completed of plant specific and industry operating experience, including License Renewal applicable ISG's (References 4 and 5), for the same time period. The first and second annual review results are documented in References 2 and 3. Enclosure 1 contains results of the third annual review.

In Reference 6, NexEra Energy Seabrook provided a revised response to RAI B.2.3.1-5 and removed the fracture mechanics evaluation as a corrective action alternative. In Reference 7, NextEra provided additional information regarding the ongoing Operating Experience Review Program. In conjunction with References 6 and 7, additional details have been added to the LRA Appendix A, UFSAR Supplement. These changes are contained in Enclosure 2.

There are no revised and one new regulatory commitment contained in this letter. Commitment Number 72 has been added to enhance the Flow-Accelerated Corrosion Program (FAC) to include management of wall thinning caused by mechanisms other than FAC. An updated LRA Appendix A - Final Safety Report Supplement Table A.3, License Renewal Commitment List is contained in Enclosure 3.

Provided in this Supplement are changes to the License Renewal Application (LRA). To facilitate understanding, the changes are explained, and where appropriate, portions of the LRA are repeated with the change highlighted by strikethroughs for deleted text and bolded italics for inserted text.

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 H. Ossing, Licensing Manager, at (603) 773-7512.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on July 2, 2013

Sincerely,

Kevin T. Walsh
Site Vice President
NextEra Energy Seabrook, LLC

Enclosure 1- Third Annual Update to the Seabrook Station License Renewal Application

Enclosure 2 – Changes to LRA Appendix A, UFSAR Supplement

Enclosure 3 - LRA Appendix A - Final Safety Report Supplement Table A.3, License Renewal Commitment List Updated to Reflect Changes.

cc:

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Enclosure 1 to SBK-L-13115

Third Annual Update to the Seabrook Station License Renewal Application

1. Flux Thimble Calibration Tube Layup

An alternate flux thimble calibration tube layup configuration has been implemented during this 3rd annual review period. In lieu of capping the flux thimble calibration tube open end, a normally closed isolation valve may serve as a pressure boundary for the calibration tube path.

In response to RAIs 3.1.1.60-01 and 3.1.1.60-02 (References 8, 9 and 10), NextEra described the movable incore detector lay-up configuration. In these responses, NextEra stated that a pressure retaining cap is installed at the end of the flux thimble calibration tube or a replacement incore detector assembly is installed which replaces the calibration tube with a solid Inconel 600 rod extending beyond the high pressure instrument connection.

Based on the above discussion, Section 2.3 of the LRA is revised as follows. No changes are needed to Section 3.1 as the isolation valves installed at the end of the calibration tubes are already listed under component type "Valve Body" on Table 3.1.2-1, line items 4, 5, and 6 on page 3.1-64.

1) In Section 2.3.1.1, on Page 2.3-5, the 3rd and 4th paragraphs of the boundary description for PID-1-RC-20845 are revised as follows:

   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 ***isolated by a normally closed valve or*** 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 ***normally closed valve or*** cap.

   The replacement incore detector assembly thimble tubes (5 out of 58) are not ***isolated by a normally closed valve or*** 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.

2. LR-ISG-2011-03: Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program XI.M41, "Buried and Underground Piping and Tanks"

LR-ISG-2011-03 recommends that applicants for license renewal revise the Buried Piping and Tanks aging management program to incorporate changes to NUREG-1801, Appendix B, Section XI.M41, Buried and Underground Piping and Tanks, as presented in the ISG.

In accordance with LR-ISG-2012-01, the following changes have been made to the NextEra Seabrook License Renewal Application, in Section B.2.1.22, as submitted in Supplement 1 dated September 29, 2010 (SBK-L-10179), Enclosure 1 and as revised in responses to: a) RAI B.2.1.9-1 and RAI B.2.22-4 (SBK-L-10204, dated December 17, 2010), b) RAI B.2.122-2 (SBK-L-11003, dated January 13, 2011), and c) Follow up RAI B.2.1.22-1, RAI B.2.1.22-3, and RAI B.2.1.22-5 (SBK-L-11062, dated April 5, 2011), .

1. On page 5 of 18, the 7th and 8th paragraphs of the "Program Description" are revised as follows:

   Hydrostatic testing may be performed in lieu of external visual inspections discussed above provided that at least 25% of the piping constructed from the material under consideration is hydrostatically tested ~~in accordance with 49 CFR 195 subpart E "Transportation of Hazardous Liquids by Pipeline Pressure Testing"~~ ***to 110 percent of the design pressure of any component within the boundary with test pressure being held for eight hours*** on an interval not to exceed 5 years.

   Internal inspection may also be performed in lieu of external visual inspections discussed above provided that at least 25% of the piping constructed from the material under consideration is internally inspected by a method capable of determining pipe wall thickness. The inspection method must be capable of detecting both general and pitting corrosion and must be qualified by Seabrook Station and accepted by the NRC. Internal inspections are to be conducted at an interval not to exceed ~~5~~ ***10*** years.

2. On page 8 of 18, the following new paragraphs are added to the end of "Element 2 - Preventive Actions":

   Fire mains are installed in accordance with NFPA Standard 24 and do not require the preventive actions of this section. Fire Protection piping is monitored as described in Element 4, Detection of Aging Effects, either by periodic flow testing or by monitoring the activity of the jockey pump.

   Because some systems or portions of systems are not cathodically protected, Seabrook Station has performed a review of plant-specific operating experience and summarized the findings in this AMP under Element 10, Operating Experience.

3. On pages 9 of 18 and 10 of 18, the 5th, 6th, and 7th paragraphs of "Element 3 – Parameters Monitored/Inspected" are revised as follows:

   To credit hydrostatic testing in lieu of visual inspection, at least 25% of the piping constructed from the material under consideration must be hydrostatically tested ~~in~~

~~accordance with 49 CFR 195 subpart E~~ ***to 110 percent of the design pressure of any component within the boundary with test pressure being held for eight hours*** on an interval not to exceed 5 years. Such testing will identify boundary leakage in significantly larger portions of the respective piping system than excavation and visual inspection of coating integrity.

To credit internal inspection, at least 25% of the piping constructed from the material under consideration is internally inspected by a method capable of determining pipe wall thickness. The inspection method must be capable of detecting both general and pitting corrosion and must be qualified by Seabrook Station and accepted by the NRC. Internal inspections are to be conducted at an interval not to exceed ~~5~~ ***10*** years.

Fire mains may be excluded from the visual inspections if subjected to a flow test as described in section 7.3 of NFPA 25, at a frequency of at least one test in each one year period, or the jockey pump operation (~~or equivalent parameter~~ ***e.g., pump starts, run time***) is monitored for unexplained changes in pump activity at an interval not to exceed once a month.

4. On page 11 of 18, the 4th paragraph of "Element 4 – Detection of Aging Effects" is revised as follows:
The number of inspections required during each 10 year interval is shown in the tables below. The number of inspections will be determined by the status of cathodic protection, coating, and adequacy of backfill materials. ~~Piping containing diesel fuel (Auxiliary Boiler fuel oil) or glycol (Diesel Generator cooling water) is treated as HAZMAT lines. The HAZMAT lines may require additional inspection criteria as shown in the table.~~

5. On page 11 of 18, sub- paragraphs (A) and (B) of "Element 4 – Detection of Aging Effects" are revised as follows:
   (A) Hydrostatic testing may be performed in lieu of the inspections described below. To credit hydrostatic testing, at least 25% of the piping constructed from the material under consideration must be hydrostatically tested ~~in accordance with 49 CFR 195 subpart E "Transportation of Hazardous Liquids by Pipeline, Pressure Testing"~~ ***to 110 percent of the design pressure of any component within the boundary with test pressure being held for eight hours*** on an interval not to exceed 5 years.

   (B) Internal inspection may be performed in lieu of the inspections described below. To credit internal inspection, at least 25% of the piping constructed from the material under consideration is internally inspected by a method capable of determining pipe wall thickness. The inspection method must be capable of detecting both general and pitting corrosion and must be qualified by Seabrook

Station and accepted by the NRC. Internal inspections are to be conducted at an interval not to exceed ~~5~~ *10* years.

6. On page 12 of 18, the table "Buried Piping Inspection Locations" in "Element 4 – Detection of Aging Effects" is replaced with the following table:

Buried Piping Inspection Locations

Material Type	Status of Cathodic Protection	GALL Category	Inspections each 10-Year Period[1]			Systems Currently in this Category
			30-40	*40-50*	*50-60*	
AL6XN	*N/A*	*N/A*	*0*	*0*	*0*	*None*
Stainless Steel	*N/A*	*N/A*	*1*	*1*	*1*	*CO, DG*
Polymeric	*N/A*	*A*	*Adequate Backfill[2]*			*FP[8]*
			1	*1*	*1*	
		B	*Inadequate Backfill[2,3]*			
			1% NTE 2	*2 % NTE 3*	*3% NTE 6*	
Steel[5]	*Installed, available and effective[4]*	*C*	*1*	*1*	*1*	*CBA, IA, FP[8], SW*
	External corrosion control not required	*D*	*1% NTE 2*	*1% NTE 2*	*1% NTE 2*	*None*
	Not practical, not installed, or installed but not meeting Cat C; non-corrosive soil[6]	*E*	*5% NTE 7*	*6% NTE 10*	*7.5% NTE 12*	*AB[7], CBA, CO, DF, DG, FW, FP[8]*
	Not installed or installed but not meeting Cat C; corrosive soil[6]	*F*	*10% NTE 15*	*12% NTE 20*	*15% NTE 25*	

GENERAL NOTES:

1. *Each inspection will examine a minimum of 10 feet of pipe or the entire length of a run, whichever is less.*
2. *The adequacy of backfill will be determined by the condition of coatings and base materials noted during inspections. If damage to the coatings or base materials are determined to have been caused by the backfill, the backfill will be considered to be "inadequate" (for the purpose of this program).*
3. *If all polymeric pipe in-scope is non-safety related, the inspection quantities may be reduced by half.*
4. *Cathodic protection is available and effective if it*
   - *was installed or refurbished 5 years prior to the end of the inspection period of interest; and*
   - *has been operational (available) at least 85 percent of the time since 10 years prior to the PEO or since installation or refurbishment (exclusive of time off-line for testing), whichever is shorter; and*
   - *has met the acceptance criteria of Section 6 at least 80 percent of the time since 10 years prior*

to the PEO or since installation or refurbishment, whichever is shorter.

5. ***If cathodic protection does not meet Category C and backfill has been determined to be inadequate, buried steel piping will be inspected as Category F.***
6. ***Soil corrosivity is determined by soil analysis using a demonstrated methodology such as EPRI report 1021470, Table 8-1. A value greater than 10 using this method is considered corrosive. The number of inspections for non-cathodically protected steel piping in corrosive soil apply only to the inspections performed during the period of extended operation.***
7. ***This line is not is use. It has been drained and flushed and is awaiting replacement per a design change. The inspection criteria for the replacement piping will be determined based on material selection, coating, cathodic protection, and quality of backfill.***
8. ***If Fire Protection piping is inspected by excavation in lieu of by alternative testing (e.g., flow test, jockey pump monitoring), and the extent of examinations is not based on the percentage of piping in the material group, the Not-to-Exceed (NTE) value will be increased by 1 inspection, if normally less than 10, or 2 inspections, if normally 10 or greater.***

7. On page 12 of 18, the table "Underground Piping Inspection Locations" in "Element 4 – Detection of Aging Effects" is revised as follows:

Underground Piping Inspection Locations

Material Type	System	~~HAZMAT~~	Inspections per 10-Year Period [1,3]
Steel	ASC[2], ASH[2]	~~No~~	***2%, NTE*** 2

GENERAL NOTES:

1. Each inspection will examine either the entire length of a run of pipe or a minimum of 10 feet.
2. ASC and ASH systems are non-safety related.
3. Cathodic protection and applied coatings do not factor into the inspection criteria for underground piping as these locations are exposed to an air indoor uncontrolled environment.

8. On page 13 of 18, the table "Inaccessible Submerged Piping Inspection Locations" in "Element 4 – Detection of Aging Effects" is revised as follows:

Inaccessible Submerged Piping Inspection Locations

Material Type	System	~~HAZMAT~~	Cathodically Protected	Applied Coatings	Inspections per 10-Year Period[1]
Steel	SW[2]	~~No~~	Yes	Yes	2[1]
Copper alloy >15% zinc	SW[3]	~~No~~	No	No	2

GENERAL NOTES:

1. Each inspection will examine either the entire length of a run of pipe or a minimum of 10 feet.
2. The Service Water vault located north of the cooling tower contains four 24" lines approximately 15' long. The valve pit located north of the cooling tower contains one 32" line less than 10' long.
3. Drain valves on the spools in the Service Water vault and valve pit are constructed of aluminum bronze (categorized as "copper alloy >15% zinc") with aluminum bronze body to bonnet bolting. These components will be inspected for loss of material when the respective Service Water spool piping is inspected by this program.

9. On page 13 of 18, the following new paragraphs are added to the end of "Element 4 - Detection of Aging Effects":

Adverse indications observed during monitoring of cathodic protection systems or during inspections are entered into the plant corrective action program. Adverse indications that are the result of inspections will result in an expansion of sample size as described below. Examples of adverse indications resulting from inspections include leaks, material thickness less than minimum, coarse backfill within 6 inches of a coated pipe or tank with accompanying coating degradation, and general or local degradation of coatings so as to expose the base material.

Adverse indications that fail to meet the acceptance criteria described in Element 6, Acceptance Criteria, will result in the repair or replacement of the affected component.

If adverse indications are detected, inspection sample sizes within the affected piping categories are doubled. If adverse indications are found in the expanded sample, an analysis is conducted to determine the extent of condition and extent of cause. The size of the follow-on inspections will be determined based on the extent of condition and extent of cause. The timing of the additional examinations should be based on the severity of the degradation identified and should be commensurate with the consequences of a leak or loss of function, but in all cases, the expanded sample inspections should be completed within the 10-year interval in which the original

adverse indication was identified. Expansion of sample size may be limited by the extent of piping or tanks subject to the observed degradation mechanism.

If adverse conditions are extensive, inspections may be halted in a piping system, or portion of system that is planned for replacement. If the initial doubling of the sample size has not been conducted, or the determination of extent of condition or extent of cause requires further inspections, these inspections should be conducted in locations with similar materials and environment.

10. On page 13 of 18, the last paragraph of "Element 5 - Monitoring and Trending" is revised as follows:
    If aging of fire mains is managed through monitoring jockey pump activity (or similar parameter), jockey pump activity (~~or similar parameter~~ ***e.g., pump starts, run time***) will be trended at least once a month to identify changes in pump activity that may be the result of increased leakage from buried fire main piping.

11. On page 13 of 18, the 1st paragraph of "Element 6 - Acceptance Criteria" is revised as follows:
    For coated piping, there should be either no evidence of coating degradation or the type and extent of coating degradation should be insignificant as evaluated by an individual possessing a NACE ~~operator qualification or by an individual otherwise meeting the qualifications to evaluate coatings as contained in 49 CFR 192 and 195~~***Coating Inspector Program Level 2 or 3 inspector qualification, or an individual has attended the Electric Power Research Institute (EPRI) Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course.***

12. On page 13 of 18, the 4th paragraph of "Element 6 - Acceptance Criteria" is revised as follows:
    ~~Criteria for pipe-to-soil potential and cathodic protection current as listed in SP0169-2007 are met or evaluated under the corrective action program.~~ ***Criteria for soil-to-pipe potential when using a saturated copper/copper sulfate reference electrode is -850mV relative to a CSE, instant off. To prevent damage to the coating, the limiting critical potential should not be more negative than -1200 mV.***

13. On page 14 of 18, the last paragraph of "Element 6 - Acceptance Criteria" is revised as follows:
    For hydrostatic tests, ~~if credited in lieu of visual inspections, the condition "without leakage" as required by 49 CFR 195.302 may be met by demonstrating that the test pressure, as adjusted for temperature, does not vary during the test.~~ ***the test acceptance criteria is no visible indications of leakage and no drop in pressure within the isolated portion of the piping that is not accounted for by a temperature change in the test media or quantified leakage across test boundary valves.***

14. On page 16 of 18, the following items are added to "Element 10 – Operating Experience" as recent industry operating experience:

    4. ***NUREG-1801, Revision 2 - December 2010***

       Although Revision 2 of NUREG-1801 (GALL) was issued subsequent to the initial issue of this program, early versions of the revision were reviewed as industry operating experience and incorporated into the Seabrook Buried Piping Aging Management Program where appropriate. On final issue of the GALL Revision 2, a gap analysis was performed to determine whether or not the Seabrook program required additional revision.

    5. ***LR-ISG-2011-03***

       In July of 2012, Interim Staff Guidance (ISG) LR-ISG-2011-03 was issued in its final form. The ISG made additional changes to GALL Revision 2 to incorporate industry experience that occurred during and subsequent to the preparation of GALL Revision 2. The ISG was used in preparation of a revised Seabrook Buried Piping Aging Management Program.

3. LR-ISG-2012-01, "Wall Thinning Due to Erosion Mechanisms"

LR-ISG-2012-01 recommends that applicants for license renewal revise the Flow Accelerated Corrosion aging management program to include management of wall thinning due to erosion by mechanisms other than FAC. The ISG also provides changes to NUREG-1801, Appendix B, Section XI.M17, Flow Accelerated Corrosion.

The following changes have been made to the NextEra Seabrook License Renewal Application in accordance with the guidance provided in LR-ISG-2012-01.

1. In Section A.2.1.8, on Page A-9, a new paragraph is added as follows:

   This program also manages wall thinning caused by mechanisms other than FAC in accordance with the guidance provided in LR-ISG-2012-01, "Wall Thinning Due to Erosion Mechanisms".

2. In Section A.3, the following commitment is added to the License Renewal Commitment List:

	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
72	***Flow-Accelerated Corrosion***	***Enhance the program to include management of wall thinning caused by mechanisms other than FAC.***	***A.2.1.8***	***Prior to entering the period of extended operation***

3. In Section B.2.1.8, Flow-Accelerated Corrosion, the following changes are made: follows:

   a. On page B-52, the following sentence is added to the end of the 1st paragraph:

With appropriate considerations, this program may also manage wall thinning caused by mechanisms other than FAC, in situations where periodic monitoring is used in lieu of eliminating the cause of various erosion mechanism(s).

b. On page B-52, the 5th paragraph is revised as follows:

This aging management program monitors the aging effects of ***wall thinning due to*** ~~flow-accelerated corrosion~~ ***FAC and erosion*** on the intended function of piping and components by measuring wall thickness~~ using non-destructive examination and performing analytical evaluations~~.

c. On page B-52, the following paragraph is added following the 6th paragraph:

For erosion mechanisms, the program includes the identification of susceptible locations based on the extent-of-condition reviews from corrective actions in response to plant-specific or industry operating experience. Components in this category may be treated in a manner similar to other "susceptible-not-modeled" lines discussed in NSAC-202L-2.

d. On page B-53, the following paragraph is added following the 1st paragraph:

For erosion mechanisms, the program includes trending of wall thickness measurements at susceptible locations to adjust the monitoring frequency and to predict the remaining service life of the component for scheduling repairs or replacements. Inspection results are evaluated to determine if assumptions in the extent-of-condition review remain valid.

e. On page B-53, the "NUREG-1801 Consistency" section is revised as follows:

This program is consistent with NUREG 1801 XI.M17 ***as amended by LR-ISG-2012-01, "Wall Thinning Due to Erosion Mechanisms".***

f. On page B-53, the "Enhancements" section is revised as follows:

~~None~~***The following enhancement will be made prior to entering the period of extended operation.***

1. The Seabrook Station Flow-Accelerated Corrosion Program will be enhanced to include management of wall thinning caused by mechanisms other than FAC.

Program Elements Affected: Element 1 (Scope of Program), Element 3 (Parameters Monitored or Inspected), Element 4 (Detection of Aging Effects), Element 5 (Monitoring and Trending), and Element 7 (Corrective Actions).

Enclosure 2 to SBK-L-13115

Changes to LRA Appendix A
UFSAR Supplement

1. In Reference 6, NextEra Energy Seabrook revised its response to RAI B.2.3.1-5 and informed the NRC that NextEra Energy Seabrook will not be using fracture mechanics evaluation for performing fatigue assessments in the aging management program associated with the Metal Fatigue of Reactor Coolant Pressure Boundary Program. As part of its revised response, the second to last paragraph of Section A.2.4.2.3, on page A-28, has also been revised as follows:

   (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, 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 reanalyzing the affected component 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).~~

2. In Reference 7, NextEra Energy Seabrook made changes to the LRA which describe corrective action and operating experience program activities. The LRA Appendix A, Section A.1.6 has been further revised as follows:

   A.1.6 Operating Experience

   The existing Corrective Action Program and the Operating Experience Program ensure, through the continual review of both plant-specific and industry operating experience, that the license renewal aging management programs are effective to manage the aging effects for which they are credited. The programs are either enhanced or new programs are developed when the review of operating experience indicates that the programs may not be effective. For each aging management program operating experience is reviewed on a continuing basis. Plant personnel responsible for screening, assigning, evaluating and submitting operating experience are trained to identify and evaluate aging related issues. Evaluation of aging related issues considers potentially affected plant systems, structures, components, materials, environments, aging effects, aging mechanisms and Aging Management Programs.

   Aging related program changes, results of inspection activities and evaluation of relevant internal and external operating experience are tracked by the NextEra action tracking/corrective action program.

   The operating experience reviews will include evaluation of applicable NUREGS, ISGs, etc., such as future revisions of NUREG-1801, "Generic Aging Lessons Learned (GALL)" Report. Programmatic features such as training of personnel, trending, record retention, self-

assessments, etc., will be in accordance with the existing NextEra corrective action and operating experience programs. ***The Corrective Action Program is part of the Quality Assurance Program, which meets the requirements of 10 CFR Part 50, Appendix B. The Operating Experience Program meets the criteria of NUREG-0737, "Clarification of TMI Action Plan Requirements," Item I.C.5, "Procedures for Feedback of Operating Experience to Plant Staff," and interfaces with and relies on active participation in the Institute of Nuclear Power Operations' operating experience program.*** Training of plant personnel will be periodic and will account for personnel turnover. Operating experience concerning aging related degradation will be reported to the industry. Any enhancements necessary to fulfill the above criteria will be put in place no later than the date the renewed operating license is issued and implemented on an ongoing basis throughout the term of the renewed license.

Enclosure 3 to SBK-L-12258

LRA Appendix A - Final Safety Report Supplement Table A.3,
License Renewal Commitment List Updated to Reflect Changes to Date

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.
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.

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
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.
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.

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
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.
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.

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
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.
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 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.

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
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.
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.

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
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.
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.

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
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 Fen 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, 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).	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
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			
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	Ongoing
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.

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
54.	Steam Generator Tube Integrity	NextEra will address the potential for cracking of the primary to secondary pressure boundary due to PWSCC of tube-to-tubesheet welds using one of the following two options: 1) Perform a one-time inspection of a representative sample of tube-to-tubesheet welds in all steam generators to determine if PWSCC cracking is present and, if cracking is identified, resolve the condition through engineering evaluation justifying continued operation or repair the condition, as appropriate, and establish an ongoing monitoring program to perform routine tube-to-tubesheet weld inspections for the remaining life of the steam generators, or 2) Perform an analytical evaluation showing that the structural integrity of the steam generator tube-to-tubesheet interface is adequately maintaining the pressure boundary in the presence of tube-to-tubesheet weld cracking, or redefining the pressure boundary in which the tube-to-tubesheet weld is no longer included and, therefore, is not required for reactor coolant pressure boundary function. The redefinition of the rector coolant pressure boundary must be approved by the NRC as part of a license amendment request.	A.2.1.10	Complete
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	Within five years 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.

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
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 detection 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 the period of extended operation.
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.	Number Not Used			
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 leakoff collection points for chlorides, sulfates, pH and iron once every three months.	A.2.1.31	Starting January 2014

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
69.	Open-Cycle Cooling Water System	Replace the Diesel Generator Heat Exchanger Plastisol PVC lined Service Water piping with piping fabricated from AL6XN material.	A.2.1.11	Prior to the period of extended operation.
70.	Closed-Cycle Cooling Water System	Inspect the piping downstream of CC-V-444 and CC-V-446 to determine whether the loss of material due to cavitation induced erosion has been eliminated or whether this remains an issue in the primary component cooling water system.	A.2.1.12	Within ten years prior to the period of extended operation.
71.	Alkali-Silica Reaction (ASR) Monitoring Program	Implement the Alkali-Silica Reaction (ASR) Monitoring Program		Prior to entering the period of extended operation.
72.	***Flow-Accelerated Corrosion***	***Enhance the program to include management of wall thinning caused by mechanisms other than FAC.***	***A.2.1.8***	***Prior to entering the period of extended operation***