NEXTera ENERGY SEABROOK

March 9, 2015

10 CFR 54

SBK-L-15005
Docket No. 50-443

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

Seabrook Station
Response to Request for Additional Information Related to the Review of the Seabrook Station License Renewal Application – Set 22 (TAC NO. ME4028)

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-14037, "Supplement 33 to NextEra Energy Seabrook License Renewal Application," March 5, 2014 (Accession Number ML14072A018)
3. NRC Letter, Request For Additional Information Related to the Review of the Seabrook Station License Renewal Application- Set 22 (TAC NO. ME4028), November 18, 2014 (Accession Number ML14300A077)
4. LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," November 22, 2013. (Accession Number ML13227A361)
5. LR-ISG-2013-01, "Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," November 14, 2014. (Accession Number ML14225A059)

In Reference 1, NextEra Energy Seabrook, LLC (NextEra Energy Seabrook) 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.

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In Reference 2, NextEra Energy Seabrook submitted changes to the License Renewal Application (LRA) in response to LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation." In Reference 2, NextEra Energy Seabrook also provided an Aging Management Program for loss of coating integrity of internal coatings or linings, which was based on draft LR-ISG-2013-01.

In Reference 3, the NRC requested additional information in order to complete the review of NextEra Energy Seabrook's License Renewal Application (LRA).

Enclosure 1 provides the responses to the request for additional information.

Enclosure 2 provides the revised "Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," to be consistent with LR-ISG-2013-01.

Enclosure 3 provides the revised AMR line item for the Diesel Generator Exhaust Manifold Flange Bolting Provided in the 4th Annual Update.

Enclosure 4 provides the revised LRA Appendix A – Updated Final Safety Analysis Report Supplement Table A.3, License Renewal Commitment List. Four new commitments have been added (#85, #86, #87 and #88) and ten commitments have been revised (#12, #74, #75, #76, #77, #78, #79, #80, #81, and #82) as a result of this Supplement.

Provided in this Supplement are changes to the 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. Edward J. Carley, Engineering Supervisor - License Renewal, at (603) 773-7957.

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 March 9, 2015.

Sincerely,

NextEra Energy Seabrook, LLC

Dean Curtland
Site Vice President

Enclosures:

Enclosure 1 - NextEra Energy Seabrook Response to Request for Additional Information Related to the Review of the Seabrook Station License Renewal Application – Set 22

Enclosure 2 - Revision to the Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks provided in SBK-L-14037 dated March 3, 2014

Enclosure 3 - Revision to the Loss of Preload AMR Line Item for Diesel Generator Exhaust Manifold Flange Bolting Provided in the 4th Annual Update (SBK-L-14173 dated October 2, 2014)

Enclosure 4 - LRA Appendix A - Final Safety Analysis Report Supplement Table A.3, License Renewal Commitment List Updated to Reflect Changes to Date

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Enclosure 1

NextEra Energy Seabrook Response to Request for Additional Information Related to the Review of the Seabrook Station License Renewal Application – Set 22

RAI 3.0.3.4-1

Background

By letter dated March 5, 2014, several aging management programs (AMPs) were revised to address loss of coating integrity. The definition of coatings that are within the scope of these changes was stated as follows:

> All coatings applied to the internal surfaces of an in-scope component if its degradation could prevent satisfactory accomplishment of any of the functions identified under 10 CFR 54.4 (a)(1), (a)(2), or (a)(3). Service Level III (augmented) coatings are those: (a) Used in areas outside of the reactor containment whose failure could adversely affect the safety function of a safety-related SSC or, (b) Applied to the internal surfaces of in-scope components and whose failure could prevent satisfactory accomplishment of any of the functions identified under 10 CFR 54.4 (a)(3).

Issue

The staff noted that the term "areas outside of the reactor containment" could exclude coatings installed on the internal surfaces of in-scope piping, piping components, heat exchangers, and tanks that are located in containment. It is not clear whether there are any internally coated in-scope piping, piping components, heat exchangers, and tanks that are located in containment.

Request

State whether there are any internally coated in-scope piping, piping components, heat exchangers, and tanks that are located in containment, and if there are, state how loss of coating integrity will be managed for these components.

NextEra Energy Seabrook Response to RAI 3.0.3.4-1

Some of the components associated with the Reactor Coolant Pump (RCP) motors such as the lube oil reservoirs and motor bearing oil coolers are internally painted with rust inhibiting paint. These components are part of RCP motor assembly. The RCP motors are periodically refurbished and replaced. The internal paintings associated with the RCP motor lube oil components are inspected and repainted as needed during the motor refurbishment process. Therefore, the elements of LR-ISG-2013-01, "Aging Management of Loss of Internal Coating or Lining Integrity for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," do not apply to these components. There are no other LR in-scope components with internal coatings or linings located inside the Containment.

RAI 3.0.3.4-2

Background

By letter dated March 5, 2014, several AMPs were modified to state that, "[c]oatings specialists and inspectors will be qualified in accordance with American Society for Testing and Materials (ASTM)."

Issue

The staff lacks sufficient information to determine whether the coatings specialist and inspectors will be adequately qualified to conduct activities associated with coating integrity. The staff has currently only evaluated ASTM standards referenced in RG 1.54.

Request

State the specific ASTM standards that will be used to qualify coatings specialist and inspectors.

NextEra Energy Seabrook Response to RAI 3.0.3.4-2

Coatings Specialists and Inspectors will be qualified in accordance with ASTM International Standards endorsed in RG 1.54, Revision 2, as it pertains to the License Renewal in-scope components addressed by LR-ISG-2013-01 (Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks).

Based on the above clarification, Item (d), on page 13 of 16 of Enclosure 2, in SBK-L-14037 dated March 5, 2014 has been revised as follows:

d. Coatings specialists and inspectors will be qualified in accordance with ASTM International Standards ***endorsed in RG 1.54, Revision 2, as it pertains to the License Renewal in-scope components addressed by LR-ISG-2013-01 (Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks).***

RAI 3.0.3.4-3

Background

By letter dated March 5, 2014, several AMPs were modified to state that, prior to conducting coating inspections, the results of the previous two inspections and any repair activities will be reviewed.

Issue

The staff noted that, while it is clear that a coatings specialist will review the inspection results prior to the next inspection, it is not clear whether this individual will prepare the post-inspection report for the prior inspections.

Request

State the qualification level of the individual who prepares the post-inspection report.

NextEra Energy Seabrook Response to RAI 3.0.3.4-3

The Coatings Inspector or Coatings Specialist will prepare the post inspection reports. Reports prepared by Coatings Inspectors will be reviewed by the Coatings Specialist.

Based on the above clarification, Item (e) on page 13 of 16 of Enclosure 2, in SBK-L-14037 dated March 5, 2014 has been revised as follows:

e. Monitoring and trending includes pre-inspection reviews of the previous two inspection results and any subsequent repair activities. ***Monitoring and Trending also includes preparation of post inspection reports by the Coatings Inspector or Coatings Specialist. Reports prepared by the Coatings Inspectors will be reviewed by the Coatings Specialist. The qualification level of the Coatings Specialists and Inspectors will be in accordance with ASTM International Standards endorsed in RG 1.54, Revision 2, as it pertains to the License Renewal in-scope components addressed by LR-ISG-2013-01 (Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks).*** The ***post inspection report*** ~~review is performed by a coatings specialist and~~ includes a list and location of all areas evidencing deterioration, a prioritization of the repair areas into areas that must be repaired before returning the system to service, areas where repair can be postponed to the next inspection, and, where possible, photographic evidence of inspection locations. When corrosion of the base material is the only issue related to coating degradation of the component, external wall thickness measurements can be used to in lieu of internal visual inspections of the coating and the corrosion rate of the base metal trended.

RAI 3.0.3.4-4

Background

By letter dated March 5, 2014, the acceptance criteria for the results of inspections associated with loss of coating integrity were added to several AMPs. Two of these are as follows:

- Blisters are evaluated by a coatings specialist and are limited to blisters that are completely surrounded by sound coating material bonded to the surface. Inspections of the base material will be conducted in the vicinity of the blister in order to determine if unanticipated corrosion has occurred.

- "Adhesion values provide reasonable assurance that the coating will remain bonded to the substrate as evaluated by the coating specialist."

Issue

The staff noted that the criteria for accepting a blister for continued service does not state whether the coating specialist will consider the potential effects of flow blockage and degradation of the base material beneath the blister. In addition, the criterion for adhesion testing results does not state how reasonable assurance that coatings will remain bonded to the substrate will be determined.

Request

State whether the potential effects of flow blockage and degradation of the base material beneath the blister will be considered in an accept-as-is disposition and how reasonable assurance that coatings will remain bonded to the substrate will be determined.

NextEra Energy Seabrook Response to RAI 3.0.3.4-4

The potential effects of flow blockage and degradation of base material beneath a blister will be considered in an accept-as-is disposition. Reasonable assurance that a coating will remain bonded to the substrate will be determined by the Coatings Specialist based on ASTM D6677 "Standard Test Method for Evaluating Adhesion by Knife" with a rating of 6 or better or ASTM D4541 "Standard Test Method for Pull-Off Strength of Coatings Using Portable Adhesion Testers" with an adhesion of 200 psi or better.

Based on the above clarification, the second bullet of item (f) on page 14 of 16 of Enclosure 2, in SBK-L-14037, dated March 5, 2014, has been revised as follows:

f. Blisters are evaluated by a coatings specialist. However, physical testing is conducted to ensure that the blister is completely surrounded by sound coating bonded to the surface. If coatings are credited for corrosion prevention, the component's base material in the vicinity of the blister is inspected to determine if unanticipated corrosion has occurred. ***The potential effects of flow blockage and degradation of base material beneath a blister will also be considered in an accept-as-is disposition. Reasonable assurance that a coating will remain bonded to the substrate will be determined by the Coatings Specialist based on ASTM D6677-07, "Standard Test Method for Evaluating Adhesion by Knife" with a rating of 6 or better or ASTM 4541-09, "Standard Test Method for Pull-Off Strength of Coatings Using Portable Adhesion Testers" with an adhesion of 200 psi or better.***

RAI 3.0.3.4-5

Background

By letter dated March 5, 2014, the "corrective actions" program elements of several AMPs were revised to state that indications will be entered into the corrective action program.

Issue

The staff noted that the programs do not state that coatings that do not meet acceptance criteria will be repaired or replaced and what testing will be conducted subsequent to the repair or replacement of coatings.

Request

State whether coatings that do not meet acceptance criteria will be repaired or replaced, and what testing will be conducted subsequent to the repair or replacement of coatings.

NextEra Energy Seabrook Response to RAI 3.0.3.4-5

The following new item (g) has been added on page 14 of 16 of Enclosure 2, in SBK-L-14037 dated March 5, 2014 as follows:

g. ***Corrective actions for coatings that do not meet acceptance criteria:***

Indications noted will be entered into the Seabrook Station Corrective Action Program for appropriate disposition.

Coatings/linings that do not meet acceptance criteria will be repaired, replaced, or removed. Testing or examination will be conducted to ensure that the extent of repaired or replaced coatings/linings encompasses sound coating/lining material.

As an alternative, coatings exhibiting indications of peeling and delamination may be returned to service if a) physical testing is conducted to ensure that the remaining coating is tightly bonded to the base metal, b) the potential for further degradation of the coating is minimized (i.e., any loose coating is removed, the edge of the remaining coating is feathered), c) adhesion testing using ASTM International standards endorsed in RG 1.54, Revision 2 is conducted at a minimum of 3 sample points adjacent to the defective area, d) an evaluation is conducted of the potential impact on the system, including degraded performance of downstream components due to flow blockage and loss of material of the coated component, and e) follow up visual inspections of the degraded coating are conducted within 2 years from detection of the degraded condition, with a re-inspection within an additional 2 years, or until the degraded coating is repaired or replaced.

If coatings/linings are credited for corrosion prevention and the base metal has been exposed or it is beneath a blister, the component's base material in the vicinity of the

degraded coating/lining is examined to determine if the minimum wall thickness is met and will be met until the next inspection.

If a blister is not repaired, physical testing is conducted to ensure that the blister is completely surrounded by sound coating/lining bonded to the surface. Physical testing consists of adhesion testing using ASTM International standards endorsed in RG 1.54, Revision 2. Where adhesion testing is not possible due to physical constraints, another means of determining that the remaining coating/lining is tightly bonded to the base metal is conducted such as lightly tapping the coating/lining. Acceptance of a blister to remain in-service should be based both on the potential effects of flow blockage and degradation of the base material beneath the blister.

RAI 3.0.3.4-6

Background

By letter dated March 5, 2014, LRA Sections A.2.1.11, Open-Cycle Cooling Water System, A.2.1.16, Fire Water System, A.2.1.18, Fuel Oil Chemistry, and A.2.1.25, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components were revised to state that the programs will manage loss of coating integrity of Service Level III (augmented) internal coatings.

Issue

The revised UFSAR sections do not provide a summary description of the aspects of the programs associated with managing loss of coating integrity, as required by 10 CFR 54.21(d). The staff noted that the changes did not include any statements related to: (a) how coatings will be inspected; (b) the testing that will be conducted for coatings that are determined to not meet the acceptance criteria; and (c) the training and qualification of individuals involved in coating/lining inspections in the UFSAR supplement updates.

Request

State the basis for why LRA Sections A.2.1.11, A.2.1.16, A.2.1.18, and A.2.1.25 provide an adequate summary description of the activities to manage loss of coating integrity for in-scope piping, piping component, heat exchanger, and tank internal coatings. Alternatively, revise LRA Sections A.2.1.11, A.2.1.16, A.2.1.18, and A.2.1.25 to provide a summary of how the programs manage this aging effect.

NextEra Energy Seabrook Response to RAI 3.0.3.4-6

In LRA Sections A.2.1.11 (Open-Cycle Cooling Water System), A.2.1.16 (Fire Water System), A.2.1.18 (Fuel Oil Chemistry), and A.2.1.25 (Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components), the following new paragraph has been added to the end of the

program descriptions.

The program also includes periodic visual inspections of all coatings/linings applied to the internal surfaces of in-scope components where loss of coating or lining integrity could impact the component's and downstream component's current licensing basis intended function. For coated/lined surfaces determined to not meet the acceptance criteria, physical testing is performed where physically possible (i.e., sufficient room to conduct testing) in conjunction with repair or replacement of the coating/lining. The training and qualification of individuals involved in coating/lining inspections of noncementitious coatings/linings are conducted in accordance with ASTM International Standards endorsed in RG 1.54, Revision 2, as it pertains to the License Renewal in-scope components addressed by LR-ISG-2013-01 (Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks). For cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces.

RAI B.2.1.25-4

Background

LRA supplement 33, dated March 5, 2014, revised the first full paragraph on LRA page B-141 to state that "approximately" 20 percent or a maximum of 25 components of each material, environment, and aging effect (MEA) combination will be inspected during each 10-year period of extended operation. LRA section A.2.1.25 states that a "representative" sample of MEA combinations will be inspected during each 10-year period of extended operation.

Issue

It is unclear what the minimum sample size to be inspected is in the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The UFSAR supplement (A.2.1.25) states that a "representative" sample will be inspected and the description of the AMP (B.2.1.25) states that "approximately" 20 percent of each MEA combination will be inspected. The definitions of "representative" and "approximately" in the context of minimum sample size are unclear.

Request

Provide clarification on the minimum sample size to be inspected in the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. Specifically, describe:

- what "approximately 20%" relates to numerically, as used in LRA section B.2.1.25 to describe the population being inspected, and
- what "representative sample" relates to numerically, as used in LRA section A2.1.25 to describe the population being inspected.

NextEra Energy Seabrook Response to RAI B.2.1.25-4

1. The 1st full paragraph of LRA Section B.2.1.25 (Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components), on page B-141, that was revised in Enclosure 1 of SBK-L-14037, dated March 5, 2014 has been clarified as follows:

   The system engineer review of inspection results will help ensure that the extent and schedule of inspections and testing detect component degradation prior to loss of intended function. The responsible engineer will ensure that an adequate number of inspections have been performed during each 10 year period during the period of extended operation. Where practical, components falling under this program will be assigned to groups of similar material, environment, and aging effect combinations. ~~Approximately~~ ***A representative sample of*** 20% ~~of each group, with~~ ***or*** a maximum of 25 components of ***each identified material, environment, and aging effect combination,*** will be inspected each 10 year period in the period of extended operation. Where practical, the population to be inspected is selected from components most susceptible to aging because of time in service and severity of operating conditions. Opportunistic inspections continue in each period despite meeting the sampling limit. ***The visual inspections assure that existing environmental conditions are not causing material degradation that could result in a loss of the component intended function.***

2. LRA Section A.2.1.25 that was revised in Enclosure 1 of SBK-L-14037, dated March 5, 2014 has been clarified as follows:

   The program inspections are inspections of opportunity, performed during pre-planned periodic system and component surveillances or during maintenance activities when the systems are opened and the surfaces made accessible for visual inspection. This maintenance may occur during power operations or refueling outages when many systems are opened. Inspections of opportunity are supplemented with focused inspections to ensure that a representative sample of ***20% or a maximum of 25 components of each identified*** material, environment, and aging effect combination~~s~~ are inspected in each 10 year period during the period of extended operation. Where practical, the population to be inspected is selected from components most susceptible to aging because of time in service and severity of operating conditions. Opportunistic inspections continue in each period despite meeting the sampling limit. The visual inspections assure that existing environmental conditions are not causing material degradation that could result in a loss of the component intended function.

RAI B.2.1.16-4

Background

LRA Supplement 33, dated March 5, 2014, states that, "[a] 3-year flow test is conducted for flow verification of the fire protection water system on a sufficient number of hydrants to determine the capacity of the system in the area tested."

Issue

Based on the statement, "capacity of the system in the area tested," [emphasis added by the staff] it is not clear to the staff that the underground piping system is tested to the worst-case design flow conditions. It is also not clear to the staff that the flow rates during the tests will be consistent enough to trend the friction loss characteristics of the underground piping system.

Request

State whether the underground piping system will be tested to the worst-case design flow conditions and the basis for why the flow rates during the tests are consistent enough to be able to trend the friction loss characteristics of the underground piping system.

NextEra Energy Seabrook Response to RAI B.2.1.16-4

A 3 year flow test is conducted for flow verification of the fire protection water system. This flow test was developed in accordance with NFPA Handbook, 14th Edition, Chapter 5, Section 11. The NFPA handbook states, "the usual procedure for conducting a flow test on a water system is to take Pitot readings on a sufficient number of hydrants to determine the capacity of the system in the area tested." This is consistent with the Seabrook procedure. The acceptance criteria in the procedure is based on the baseline data. The baseline data initially met the acceptance testing of the system which was based on design. Testing since then has consistently met and exceeded the acceptance criteria and demonstrates compliance with NFPA 25 (2011 Edition), Section 7.3.

RAI B.2.1.16-5

Background

LRA Supplement 33, dated March 5, 2014, states that internal inspections will be conducted on the fire protection water storage tanks (FWSTs) every 5 years.

Issue

It is not clear to the staff whether the additional tests and inspections cited in NFPA 25 Section 9.2.7 will be conducted if pitting and general corrosion to below nominal wall depth and any coating failure in which bare metal is exposed (reference Table 4a footnote 4) is detected.

Request

State whether the additional tests and inspections specified in NFPA 25 Section 9.2.7 will be conducted if degradation described in Table 4a footnote 4 is detected.

NextEra Energy Seabrook Response to RAI B.2.1.16-5

NFPA 25 (2011 Edition) will be followed for interior tank inspections including additional tests and inspections specified in Section 9.2.7 in the event that it is required by Section 9.2.6.4, which states "Steel tanks exhibiting signs of interior pitting, corrosion, or failure of coating shall be tested in accordance with 9.2.7."

Based on the above discussion, the following changes have been made to the LRA.

a) Item (8), on Page 8 of 45, in Enclosure 1 of SBK-L-14037 dated March 5, 2014 has been revised as follows:

    8. Water Storage Tanks - Interior Inspection

    Per LRA Appendix B, Section B.2.1.16 and current commitment #13, the internal bottom surface of the two fire protection water storage tanks will be UT inspected and evaluated within ten years prior to the period of extended operation.

    Fire Protection Water Storage Tanks are inspected on a 5 year interval for adherent scale, coating bubbles or blisters, delamination of coating, pitting, corrosion, spalling, rot or other forms of deterioration, and aquatic growth (tubercules and slimes shall be sampled, if possible, and tested for microbiological influenced corrosion); recirculation lines, pipe supports, and other piping is inspected; the anti-vortex plate is inspected for deterioration or blockage. When inspections are made by means of underwater evaluation, silt is removed from the tank floor to facilitate the inspection. ***Additional tests and inspections specified in Section 9.2.7 of NFPA 25 (2011 Edition) will be followed in the event that it is required by Section 9.2.6.4, which states "Steel tanks exhibiting signs of interior pitting, corrosion or failure of coating shall be tested in accordance with 9.2.7."***

    This activity is consistent with NFPA 25 (2011 Edition).

b) The new paragraph that was added to Appendix B, Section B.2.1.16 (Fire Water System) under Item (7), on Page 23 of 45, in Enclosure 1 of SBK-L-14037 dated March, 2014 has been revised as follows:

    7. Periodic inspection and testing of the fire water storage tanks is performed using the guidance in NFPA 25 (2011 Edition). The exterior surfaces of the tanks are inspected annually. Internal inspections are performed on a 5 year interval for adherent scale, coating bubbles or blisters, delamination of coating, pitting, corrosion, spalling, rot or other forms of deterioration and aquatic growth. ***Additional tests and inspections specified in Section 9.2.7 of NFPA 25 (2011 Edition) will be followed in the event that it is required by Section 9.2.6.4, which states "Steel tanks exhibiting signs of interior pitting, corrosion or failure of coating shall be tested in accordance with 9.2.7."*** UT inspection and evaluation of the internal bottom surface of the two fire water storage tanks is to be performed within ten years prior to the period of extended operation.

c) In LRA Appendix B, Section B.2.1.16 (Fire Water System), on Page B-101, a new enhancement #10 has been added as follows:

10. ***Enhance the Fire Water System Program to perform additional tests and inspections on the Fire Water Storage Tanks as specified in Section 9.2.7 of NFPA 25 (2011 Edition) in the event that it is required by Section 9.2.6.4, which states "Steel tanks exhibiting signs of interior pitting, corrosion, or failure of coating shall be tested in accordance with 9.2.7."***

d) In LRA Appendix A, Section A.3, a new Commitment #85 has been added as follows:

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
85.	***Fire Water System***	***Enhance the program to perform additional tests and inspections on the Fire Water Storage Tanks as specified in Section 9.2.7 of NFPA 25 (2011 Edition) in the event that it is required by Section 9.2.6.4, which states "Steel tanks exhibiting signs of interior pitting, corrosion, or failure of coating shall be tested in accordance with 9.2.7."***	***A.2.1.16***	***Prior to the period of extended operation.***

RAI B.2.1.16-6

Background

LRA Supplement 33, dated March 5, 2014, states that, "[w]ater spray fixed systems strainers are cleaned every 5 years during the wet sprinkler alarm valve inspection/maintenance, deluge or sprinkler flooding valve inspection/maintenance, and deluge or sprinkler multimatic valve inspection/maintenance."

Issue

The staff noted that LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," AMP XI.M27 Table 4a, "Fire Water System Inspection and Testing Recommendations," states that strainers should be inspected every refueling outage interval and after each system actuation. The staff also noted that NFPA 25 Section 10.2.1.7 allows mainline strainer inspections to be conducted every 5 years. It is not clear to the staff whether the term "inspection" in the LRA supplement means flow test or a visual inspection of some nature and whether "maintenance" means any opening of the system such that the strainers are accessible.

Request

Regarding LRA Supplement 33, state whether the term "inspection" includes flow tests and whether "maintenance" means any opening of the system such that the strainers are accessible.

NextEra Seabrook Response to RAI B.2.1.16-6

The current Station procedure titles use the term inspection/maintenance and hence, the reason behind the use of this term in the original response letter. The terminology

inspection/maintenance with respect to water spray fixed systems strainers includes disassembly and cleaning of the strainer basket and body. The term "inspection" does not include flow tests. The term maintenance includes disassembly of the strainers so that the strainer baskets and strainer bodies can be cleaned.

With respect to the issue related to the frequency of the strainer inspections and cleaning (i.e., LR-ISG-2012-02 states that strainers should be inspected every refueling outage whereas NFPA 25, Section 10.2.1.7, allows strainer inspections be conducted every five years). The source of the fire water system at Seabrook Station is potable water supplied from the town of Seabrook. Therefore, disassembly and cleaning of the strainers every five years is adequate. More frequent inspections would be necessary if the fire water source was likely to contain obstructive material, such as for fire water systems supplied from a lake or river.

Based on the above discussion, item 11, on page 9 of 45, in Enclosure 1 of SBK-L-14307 has been revised as follows:

11. Water Spray Fixed Systems - Strainers

    Water spray fixed systems strainers are cleaned every 5 years during the wet sprinkler alarm valve inspection/maintenance, deluge or sprinkler flooding valve inspection/maintenance, and deluge or sprinkler multimatic valve inspection/maintenance. ***Inspection/Maintenance of the strainers includes disassembly and cleaning of the strainer basket and body.***

    This activity is consistent with NFPA 25 (2011 Edition).

Additionally, SBK-L-14037 dated March 5, 2014, only addressed the deluge/preaction sprinkler system trim piping strainers. NextEra Energy Seabrook also has mainline strainers that are installed upstream of the deluge/preaction sprinkler system trim piping strainers. Since the fire water system at Seabrook Station is potable water supplied from the town of Seabrook, these strainers are currently not inspected. However, the following new enhancement is added to B.2.1.16 (Fire Water System) and a new commitment #86 is made to disassemble, inspect, and clean the mainline strainers every five years per the guidance provided in NFPA 25 (2011 Edition), Section 10.2.1.7. Similar to the deluge/preaction sprinkler system strainers, inspection of the mainline strainers on a frequency of every five years is adequate since the fire water system supply is potable water from the town of Seabrook.

a) In LRA Appendix B, Section B.2.1.16 (Fire Water System), on Page B-101, a new enhancement #11 has been added as follows:

    11. Enhance the Fire Water System Program to include disassembly, inspection, and cleaning of the mainline strainers every five years per the guidance provided in NFPA 25 (2011 Edition), Section 10.2.1.7.

b) In LRA Appendix A, Section A.3, a new Commitment #86 has been added as follows:

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
86.	***Fire Water System***	***Enhance the program to include disassembly, inspection, and cleaning of the mainline strainers every 5 years.***	*A.2.1.16*	***Prior to the period of extended operation.***

RAI B.2.1.16-7

Background

LRA Supplement 33, dated March 5, 2014, states that, "[a]n Open Head Spray Nozzle Air Flow Test is performed every 3 years to verify that the open heads and branch lines on the deluge system are free of debris and not blocked. This is done by connecting the selected deluge system to the service air system and observing air flow through each sprinkler head."

Issue

The staff noted that NFPA 25 Section 13.4.3.2.2.4 allows deluge valve flow test frequencies to not exceed 3 years; however, LR-ISG-2012-02 AMP XI.M27 Table 4a states that water spray fixed system operational tests should be conducted on a refueling outage interval.

Request

State the basis for conducting deluge valve flow testing every 3 years instead of on a refueling outage interval.

NextEra Energy Seabrook Response to RAI B.2.1.16-7

The frequency of Open Head Spray Nozzle Air Flow Test will be increased to every refueling outage to verify that the open heads and branch lines on the deluge system are free of debris and not blocked to be consistent with LR-ISG-2012-02, AMP XI.M27, Table 4a.

Based on the above discussion, the following changes have been made to the LRA.

a) Item (10), on page 9 of 45, in Enclosure 1 of SBK-L-14037 dated March 5, 2014 has been revised as follows:

10. Valves and System-Wide Testing - Deluge Valves

    The auto initiation of deluge spray and preaction sprinkler system valves is tested every 18 months by an actuation signal from the local fire alarm panel. Alarms must be generated at the detectors or at a remote manual pull station to achieve the automatic activation. Main drain flow verification will be performed for each system tested to ensure that the isolation valve that was closed for the test has not failed and has been returned to full open and to verify the operability of all the flow alarms. This is done by

performing a test to simulate a flow to the flow alarm pressure switch, and a test of the air or nitrogen supervisory system low pressure alarm, if applicable.

The Fire Water System Program will be enhanced to revise the frequency of deluge and preaction valve actuation testing to annually, consistent with NFPA 25 (2011 Edition) Section 13.4.3.2.2 (Ref. new commitment #76).

An Open Head Spray Nozzle Air Flow Test is ***currently*** performed every 3 years to verify that the open heads and branch lines on the deluge system are free of debris and not blocked. This is done by connecting the selected deluge system to the service air system and observing air flow through each sprinkler head. ***The frequency of this test will be increased to every refueling outage to be consistent with LR-ISG-2012-02, AMP XI.M27, Table 4a (Reference new Commitment #87).***

~~This activity is consistent with NFPA 25 (2011 Edition).~~

b) In LRA Appendix B, Section B.2.1.16 (Fire Water System), on Page B-101, a new enhancement #12 has been added as follows:

12. Increase the frequency of the Open Head Spray Nozzle Air Flow Test from every 3 years to every refueling outage to be consistent with LR-ISG-2012-02, AMP XI.M27, Table 4a.

c) In LRA Appendix A, Section A.3, a new Commitment #87 has been added as follows:

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
87.	***Fire Water System***	***Increase the frequency of the Open Head Spray Nozzle Air Flow Test from every 3 years to every refueling outage to be consistent with LR-ISG-2012-02, AMP XI.M27, Table 4a.***	***A.2.1.16***	***Prior to the period of extended operation.***

RAI B.2.1.16-8

Background

LRA Supplement 33, dated March 5, 2014, states that the Fire Water System Program "will be enhanced to conduct an inspection of piping and branch line conditions every 5 years by opening a flushing connection at the end of one main and by removing a sprinkler toward the end of one branch line for the purpose of inspecting for the presence of foreign organic and inorganic material...."

Issue

The staff noted that NFPA 25 Section 14.2.2 specifies that, on an alternating schedule, an internal inspection of every other wet pipe system in buildings with multiple wet pipe systems should be conducted every 5 years. The staff lacked sufficient information to complete its evaluation of the enhancement because it is not clear whether there are multiple wet pipe systems in any of the structures containing in-scope fire water systems.

Request

State if there are multiple wet pipe systems in any of the structures containing in-scope fire water systems and, if there are, state the basis for why testing is not conducted on every other system every 5 years.

NextEra Energy Seabrook Response to RAI B.2.1.16-8

There are no multiple wet pipe systems in any of the structures containing in-scope fire water systems.

RAI B.2.1.16-9

Background

LRA Supplement 33, dated March 5, 2014, states that the plant-specific installation specification for the fixed fire suppression system included a requirement that, "all piping shall be pitched to permit complete drainage of the system. Drain valves shall be provided at all low points of the system." Based on this, it was stated that no changes were required to address normally-dry pipe that is periodically wetted where piping segments allow water to collect.

Issue

The staff noted that despite appropriate construction specifications, field installation can result in deviations. In addition, during the first few operational cycles of systems (e.g., system flow), minor changes in pipe elevations can occur. It is not clear to the staff how it was confirmed that there were no piping segments that could allow water to collect in the fire water normally-dry but periodically-wetted piping.

Request

State how it was confirmed that there were no piping segments that could allow water to collect in the fire water normally-dry but periodically-wetted piping.

NextEra Energy Seabrook Response to RAI B.2.1.16-9

The only sprinkler system that is normally-dry but periodically-wetted is the deluge system for the transformers. Water is used for testing this system. Air is used for testing of all other normally dry systems. There are existing drain holes for each branch connection associated with the transformer deluge system. The test procedure will be enhanced to verify drain holes are draining after each test to ensure complete drainage of the system.
Based on the above discussion, the following changes are made to the LRA.

a) Item (13)(d) , on page 10 of 45, in Enclosure 1 of SBK-L-14037 dated March 5, 2014 has been revised as follows:

d. ~~The Station's Fixed Fire Suppression Systems installation specification states that "[a]ll piping shall be pitched to permit complete drainage of the system. Drain valves shall be provided at all low points of the system." Therefore, no further change is necessary.~~

The only sprinkler system that is normally-dry but periodically-wetted is the deluge system for the transformers. Water is used for testing this system. Air is used for testing of all other normally dry systems. There are existing drain holes for each branch connection associated with the transformer deluge system. The test procedure will be enhanced to verify drain holes are draining after each test to ensure complete drainage of the system.

b) In LRA Appendix B, Section B.2.1.16 (Fire Water System), on Page B-101, the following new paragraph has been added to the Program Description.

The deluge system associated with the transformers is normally-dry but wetted during transformer deluge system testing. There are existing drain holes for each branch connection associated with the transformer deluge system. The test procedure will be enhanced to verify drain holes are draining after each test to ensure complete drainage of the system.

c) In LRA Appendix B, Section B.2.1.16 (Fire Water System), on Page B-101, a new enhancement #13 has been added as follows:

13 The Fire Water System Program will be enhanced to include verification that the drain holes associated with the transformer deluge system are draining to ensure complete drainage of the system after each test.

d) In LRA Appendix A, Section A.3, a new Commitment #88 has been added as follows:

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
88.	***Fire Water System***	***Enhance the program to include verification that the drain holes associated with the transformer deluge system are draining to ensure complete drainage of the system after each test.***	***A.2.1.16***	***Within five years prior to the period of extended operation.***

<u>RAI B.2.1.16-10</u>

<u>Background</u>

The LRA Supplement 33, dated March 5, 2014, changes to the "acceptance criteria" program element of the Fire Water System Program did not address all the recommendations in the "acceptance criteria" program element of LR-ISG-2012-02, which states in part that, if foreign

organic or inorganic material sufficient to obstruct piping or sprinklers is detected, the material should be removed and its source determined and corrected.

Issue

It is not clear to the staff whether an exception was taken to this portion of the recommendations in the "acceptance criteria" program element of LR-ISG-2012-02.

Request

State what actions will be taken if foreign organic or inorganic material sufficient to obstruct piping or sprinklers is detected.

NextEra Energy Seabrook Response to B.2.1.16-10

If the presence of sufficient foreign organic or inorganic material to obstruct pipe or sprinklers is detected during pipe inspections, the material will be removed and its source is determined and corrected in accordance with the acceptance criteria element of LR-ISG-2012-02.

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

a) Item (13)(a), on page 9 of 45, in Enclosure 1 of SBK-L-14037 dated March 5, 2014 has been revised as follows:

   13. Obstruction Investigation - Internal Inspection of Piping

      a. The Fire Water System Program will be enhanced to conduct an inspection of piping and branch line conditions every 5 years by opening a flushing connection at the end of one main and by removing a sprinkler toward the end of one branch line for the purpose of inspecting for the presence of foreign organic and inorganic material, per the guidance provided in NFPA 25 (2011 Edition) Section 14.2.2. ***If the presence of sufficient foreign organic or inorganic material to obstruct pipe or sprinklers is detected during pipe inspections, the material will be removed and its source is determined and corrected.*** (Ref. new Commitment #75).

b) Enhancement #5, on page 24 of 45, in Enclosure 1 of SBK-L-14037 dated March 5, 2014 has been revised as follows:

   5. The Fire Water System Program will be enhanced to ***a)*** conduct an inspection of piping and branch line conditions every 5 years by opening a flushing connection at the end of one main and by removing a sprinkler toward the end of one branch line for the purpose of inspecting for the presence of foreign organic and inorganic material per the guidance provided in NFPA 25 (2011 Edition), ***b) if the presence of sufficient foreign organic or inorganic material to obstruct pipe or sprinklers is detected during pipe inspections, the material will be removed and its source is determined and corrected.***

c) In LRA Appendix A, Section A.3, Commitment #75 has been revised as follows. The schedule date for Commitment #13 has also been revised to be consistent with LR-ISG-2012-02, Appendix B, Page B-1.

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
75.	Fire Water System	Enhance the program to ***a)*** conduct an inspection of piping and branch line conditions every 5 years by opening a flushing connection at the end of one main and by removing a sprinkler toward the end of one branch line for the purpose of inspecting for the presence of foreign organic and inorganic material per the guidance provided in NFPA 25 (2011 Edition) ***and b) If the presence of sufficient foreign organic or inorganic material to obstruct pipe or sprinklers is detected during pipe inspections, the material will be removed and its source is determined and corrected.***	A.2.1.16	***Prior to the period of extended operation.*** ~~Within ten years prior to the period of extended operation.~~

RAI B.2.1.16-11

Background

As amended by letter dated March 5, 2014, LRA Section B.2.1.16 states an enhancement to the "detection of aging effects" program element as follows:

> The Seabrook Station Fire Water System Program will be enhanced to include the performance of periodic visual inspection or volumetric inspection, as required, of the internal surface of the fire protection system upon each entry to the system for routine or corrective maintenance to evaluate wall thickness and inner diameter of the fire protection piping ensuring that corrosion product buildup will not result in flow blockage due to fouling. Where surface irregularities are detected, follow-up volumetric examinations are performed. This inspection will be performed no earlier than 10 years before the period of extended operation.

Issue

The staff noted that the last sentence of this enhancement had been revised by letter dated November 15, 2010, to state, "[t]hese inspections will be performed within ten years prior to the period of extended operation." It is not clear to the staff: (a) why the sentence reverted to the original wording of the enhancement; (b) why the term "This" inspection was used when the

enhancement implies that periodic inspections will be conducted; and (c) if the intent is to conduct periodic inspections in the 10-year period prior to the period of extended operation and during the period of extended operation, why this sentence does not refer to the inspections "commencing" during the 10-year period prior to the period of extended operation.

Request

Clarify the intent and the wording of Enhancement No. 3 and Commitment No. 11.

NextEra Energy Seabrook Response to RAI B.2.1.16-11

(a) In SBK-L-10192 dated November 15, 2010, several terminologies used in the LRA Commitment list such as "Within ten years of entering the period of extended operation" and "No earlier than 10 years before the period of extended operation" were changed to read "Within ten years prior to the period of extended operation." This change was made for consistency purposes. The change in the wording has no impact on the technical content or implementation schedule of Commitment #11, (b) The term "This inspection" was changed to "These inspections" since the inspections will be multiple in nature, (c) The intent of Commitment #11 is to "commence" the inspections during the 10-year period prior to entering the period of extended operation. Further clarification is provided below.

Enhancement 3 provided in SBK-L-14037 inadvertently reflects the original wording provided in the License Renewal Application (Ref. 1). In SBK-L-10192 dated November 15, 2010 (Enclosure 4, Page 7 of 8) and SBK-L-10204 dated December 17, 2010 (Enclosure 1, Pages 11 and 13 of 42), Enhancement 3 was revised to read as described below. The wording used for Enhancement 3 is consistent with Commitment #11. Italics reflect what was added in SBK-L-14037 dated March 5, 2014.

3. The Seabrook Station Fire Water System Program will be enhanced to include the performance of periodic visual inspection or volumetric inspection, as required, of the internal surface of the fire protection system upon each entry to the system for routine or corrective maintenance to evaluate wall thickness and inner diameter of the fire protection piping *ensuring that corrosion product buildup will not result in flow blockage due to fouling. Where surface irregularities are detected, follow-up volumetric examinations are performed.* 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.

Additionally, the schedule date for Commitments #74, #75, #76, and #77, which were added in SBK-L-14037 dated March 5, 2014, were inadvertently written as "Within ten years prior to the period of extended operation". The correct schedule date for these commitments is "Prior to the period of extended operation", which is consistent with the guidance provided in LR-ISG-2012-02, Appendix B, Page B-1.

The revised commitment schedules are as follows:

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
74.	Fire Water System	Enhance the program to perform sprinkler inspections annually per the guidance provided in NFPA 25 (2011 Edition). Inspection will ensure that sprinklers are free of corrosion, foreign materials, paint, and physical damage and installed in the proper orientation (e.g., upright, pendant, or sidewall). Any sprinkler that is painted, corroded, damaged, loaded, or in the improper orientation, and any glass bulb sprinkler where the bulb has emptied, will be evaluated for replacement.	A.2.1.16	***Prior to the period of extended operation.*** ~~Within ten years prior to the period of extended operation~~
75.	Fire Water System	Enhance the program to a) conduct an inspection of piping and branch line conditions every 5 years by opening a flushing connection at the end of one main and by removing a sprinkler toward the end of one branch line for the purpose of inspecting for the presence of foreign organic and inorganic material per the guidance provided in NFPA 25 (2011 Edition) and b) If the presence of sufficient foreign organic or inorganic material to obstruct pipe or sprinklers is detected during pipe inspections, the material will be removed and its source is determined and corrected.	A.2.1.16	***Prior to the period of extended operation.*** ~~Within ten years prior to the period of extended operation~~
76.	Fire Water System	Enhance the program to conduct the following activities annually per the guidance provided in NFPA 25 (2011 Edition). • main drain tests • deluge valve trip tests • fire water storage tank exterior surface inspections	A.2.1.16	***Prior to the period of extended operation.*** ~~Within ten years prior to the period of extended operation~~

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
77.	Fire Water System	The Fire Water System Program will be enhanced to include the following requirements related to the main drain testing per the guidance provided in NFPA 25 (2011 Edition). • The requirement that if there is a 10 percent reduction in full flow pressure when compared to the original acceptance tests or previously performed tests, the cause of the reduction shall be identified and corrected if necessary. • Recording the time taken for the supply water pressure to return to the original static (nonflowing) pressure.	A.2.1.16	***Prior to the period of extended operation.*** ~~Within ten years prior to the period of extended operation~~

RAI B.2.1.17-6

Background

As revised by LR-ISG-2012-02, SRP-LR Table 3.0-1 states that external visual examinations are sufficient to monitor the degradation of caulking and sealant when supplemented with physical manipulation. By letter dated December 17, 2010, the UFSAR Supplement (LRA sections A.2.1.17) was revised to include visual inspection of caulking and sealant, in response to RAI B.2.1.17-2. The Aboveground Steel Tanks Program (LRA section B.2.1.17) was also revised to include the tactile examination of caulking and sealant, in response to RAI B.2.1.17-3.

Issue

The UFSAR Supplement (LRA sections A.2.1.17) does not specifically state that visual examinations of caulking and sealant will be augmented by physical manipulation.

Request

Provide the justification for not augmenting visual examinations of caulking and sealant with physical manipulation.

NextEra Energy Seabrook Response to RAI B.2.1.17-6

In LRA Section A.2.1.17, "Above Ground Steel Tanks", a new paragraph has been added after the 3rd paragraph as follow:

Inspection for degradation of the sealant and caulking will be performed with a visual and tactile examination (manual manipulation) consisting of pressing on the sealant or caulking to detect a reduction in the resiliency and pliability.

RAI B.2.1.17-7

Background

By letter dated March 5, 2014, the Aboveground Steel Tanks Program (LRA section B.2.1.17) was revised in response to LR-ISG-2012-02. Enhancement 1 was revised to include additional in-scope aboveground metallic tanks. Enhancement 2 revised the implementing procedures of the Aboveground Steel Tanks Program to be consistent with the staff's revised guidance in Table 4a, Tank Inspection Recommendations, of LR-ISG-2012-02.

Issue

The enhancements to the Aboveground Steel Tanks Program are not reflected in the applicant's commitment (Commitment No. 12) to implement the AMP. Furthermore, it is unclear what requirements the current commitment (Commitment No. 12) is referring to when it states "components and aging effects required by the Aboveground Steel Tanks" Program.

Request

Describe how the Enhancements to the Aboveground Steel Tanks Program are captured in a commitment. Clarify what requirements are being referenced in Commitment No.12.

NextEra Energy Seabrook Response to RAI B.2.1.17-7

In LRA Appendix A, Section A.3, commitment #12 has been revised as follows:

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
12.	Aboveground Steel Tanks	Enhance the program to include ***1) In-scope outdoor tanks, except fire water storage tanks, constructed on soil or concrete, 2) Indoor large volume storage tanks (greater than 100,000 gallons) designed to near-atmospheric internal pressures, sit on concrete or soil, and exposed internally to water, 3) Visual, surface, and volumetric examinations of the outside and inside surfaces for managing the aging effects of loss of material and cracking, 4) External visual examinations to monitor degradation of the protective paint or coating, and 5) Inspection of sealant and caulking for degradation by performing visual and tactile examination (manual manipulation) consisting of pressing on the sealant or caulking to detect a reduction in the resiliency and pliability.*** ~~components and aging effects required by the Aboveground Steel Tanks and to perform visual, surface, and volumetric examinations of the outside and inside surfaces for managing the aging effects of loss of material and cracking.~~	A.2.1.17	Within 10 years prior to the period of extended operation

RAI B.2.1.24-3

Background

By letter dated March 5, 2014, NextEra Energy (the applicant) provided its response to NRC License Renewal Interim Staff Guidance (LR-ISG) No. LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation" (ADAMS Accession Number ML13227A361). In this letter the applicant amended the External Surfaces Monitoring Program (LRA Section B.2.1.24) to include aging management bases for managing loss of material due to corrosion under insulation and cracking due stress corrosion cracking for insulated components at the facility. The applicant also amended UFSAR Supplement Table A.3 to include LRA Commitment No. 78 to state that the AMP will be enhanced to include periodic inspections of in-scope insulated components for possible corrosion under insulation and that the enhancement of the program will be completed prior to the period of extended operation.

Issue

In the applicant's letter of May 5, 2014, the applicant only amended the program description of the External Surfaces Monitoring Program to include the details and basis for managing loss of material due to corrosion under insulation at the facility. The applicant did not incorporate this detailed basis into the UFSAR Supplement for the AMP or into the provision of LRA Commitment No. 78.

Request

Justify why the basis and programmatic criteria for managing loss of material due to corrosion under insulation in the revised description for LRA AMP B.2.1.24, "External Surfaces Monitoring," have not been incorporated into a revision of either LRA UFSAR Supplement Section A.2.1.14, "External Surfaces Monitoring," or LRA Commitment No. 78, which was provided in the letter of March 5, 2014.

NextEra Energy Seabrook Response to RAI B.2.1.24-3

1. In LRA Appendix A, Section A.2.1.24 (External Surfaces Monitoring), on Page A-14, the last paragraph has been revised as follows:

   The External Surfaces Monitoring Program includes visual inspections on insulation jacketing to ensure that no aging effects are impairing the function of the thermal insulation. The External Surfaces Monitoring Program ***also*** includes periodic inspections of in-scope insulated components for possible corrosion under insulation. ***A sample of outdoor component surfaces that are insulated and a sample of indoor insulated components exposed to condensation (due to the in-scope component being operated below the dew point), will be periodically inspected every 10 years during the period of extended operation. Subsequent inspections will consist of examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the***

insulation if the initial inspection verifies no loss of material or cracking. If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or there is evidence of water intrusion through the insulation (e.g. water seepage through insulation seams/joints), periodic inspections under the insulation will continue as conducted for the initial inspection.

2. In LRA Appendix A, Section A.3, Commitment #78 has been revised as follows:

78.	External Surfaces Monitoring	Enhance the program to include periodic inspections of in-scope insulated components for possible corrosion under insulation. ***A sample of outdoor component surfaces that are insulated and a sample of indoor insulated components exposed to condensation will be periodically inspected every 10 years during the period of extended operation.***	A.2.1.8***24***	Prior to the period of extended operation.

RAI B.2.1.11-3

Background

By letter dated March 5, 2014, NextEra Energy (the applicant) provided its response to NRC License Renewal Interim Staff Guidance (LR-ISG) 2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation" (ADAMS Accession Number ML13227A361). In this letter, the applicant amended the AMR tables for the auxiliary (Aux) systems and steam and power conversion (SPC) systems to include new AMR items for insulated piping and fitting components which are exposed to either external condensation, external uncontrolled indoor air, or external outdoor air environmental conditions.

Issue

Part 1 – In the letter of March 5, 2014, the applicant amended LRA Table 2.3.3-4 for the chlorination system to include "Insulated Piping and Fittings" as a new, in-scope component type for the system. However, the applicant did not amend LRA Table 3.3.2-4, Summary of Aging Management Evaluation – Chlorination System, to include applicable AMR items for insulated components in the chlorination system.

Part 2 – In the letter of March 5, 2014, the applicant amended LRA Table 2.3.4-2 for the auxiliary steam condensate system and LRA Table 2.3.4-4 for the circulating water system to include "Insulated Piping and Fittings" as a new, in-scope component type for the systems. However, the applicant did not amend LRA Table 3.4.2-2, Summary of Aging Management Evaluation – Auxiliary Steam Condensate System, and LRA Table 3.4.2-4, Summary of Aging Management Evaluation – Circulating Water System, to include applicable AMR items for insulated components in the systems.

Request

Part 1 – Provide your basis (i.e., justify) for not amending LRA Table 3.3.2-4, Summary of Aging Management Evaluation – Chlorination System, to include applicable AMR items for insulated piping and fitting components in the chlorination system. If it is determined that LRA

Table 3.3.2-4 should have been amended to include applicable AMR items for insulated piping and fittings in the chlorination system, identify: (a) the material(s) of fabrication and environment(s) for the insulated piping and fittings in the chlorination system, (b) the aging effects that are applicable to the material-environment combinations for insulated piping and fittings in the system, and (c) the aging management program that will be used to manage these aging effects during the period of extended operation. Amend LRA Table 3.3.2-4 accordingly.

Part 2 – Provide your basis (i.e., justify) for not amending LRA Table 3.4.2-2, Summary of Aging Management Evaluation – Auxiliary Steam Condensate System, and LRA Table 3.4.2-4, Summary of Aging Management Evaluation – Circulating Water System, to include applicable AMR items for insulated piping and fitting components in the systems. If it is determined that LRA Tables 3.4.2-2 and 3.4.2-4 should have been amended to include applicable AMR items for insulated piping and fittings in the auxiliary steam condensate system and the circulating water system, identify: (a) the material(s) of fabrication and environment(s) for the insulated piping and fittings in systems, (b) the aging effects that are applicable to the material-environment combinations for insulated piping and fittings in the systems, and (c) the aging management program that will be used to manage these aging effects during the period of extended operation. Amend LRA Tables 3.4.2-2 and 3.4.2-4 accordingly.

NextEra Energy Seabrook Response to RAI B.2.1.11-3

Responses to Part 1 and Part 2

There are no insulated piping and fittings in the Chlorination, Auxiliary Steam Condensate, and Circulating Water systems that require aging management for corrosion under insulation. These systems were inadvertently added to item (H) on Page 41 of 45 of Enclosure 1 of SBK-L-14037. Therefore, new AMR line items for insulated piping and fittings are not required for these three systems. Items (I)(a) through (I)(k) between Pages 41 and 45 in Enclosure 1 of SBK-L-14037 accurately describe the systems with insulated piping and fittings and the new AMR line items that were added for these systems to manage corrosion under insulation.

Based on the above discussion, item number (H) on Page 41 of 45, in Enclosure 1 of SBK-L-14037, dated March 5, 2014 has been revised as follows to match the systems presented in item (I):

H. The following new component types have been added to Tables ~~2.3.3-4 (Chlorination System)~~ ***2.3.3-9 (Control Building Air Handling)***, 2.3.3-10 (Demineralized Water System), 2.3.3-12 (Diesel Generator), 2.3.3-15 (Fire Protection System), 2.3.3-27 (Potable Water System), ***2.3.3-28 (Primary Auxiliary Building Air Handling System)***, 2.3.3-29 (Primary Component Cooling Water System), 2.3.3-37 (Service Water System), ~~2.3.4-2 (Auxiliary Steam Condensate System), 2.3.4-4 (Circulating Water System),~~ 2.3.4-5 (Condensate System), 2.3.4-6 (Feedwater System), and 2.3.4-7 (Main Steam System).

RAI B.2.1.11-4

Background

By letter dated March 5, 2014, Seabrook provided its response to License Renewal Interim Staff Guidance (LR-ISG)-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation." With regard to recurring internal corrosion (RIC), the response states that loss of material due to RIC has been detected in the cement lined carbon steel piping in the service water system (SWS) and that this aging effect is being managed by LRA AMP B.2.1.11, Open-Cycle Cooling Water System Program. With regard to the adequacy of augmented inspections, the response states that visual inspections of the pipe liner have enabled identification of under-liner corrosion due to liner degradation or defects, and once located, actual wall loss can be evaluated using ultrasonic testing (UT). With regard to decision points where increased inspections would be implemented, the response states that maintenance strategies are assessed to determine if changes are warranted following the identification of any new degradation.

Issue

The response to LR-ISG-2012-02 states that the amount of wall loss in a component exhibiting signs of corrosion can be evaluated through UT wall thickness measurements. However, the response does not firmly establish that a component will be monitored for wall loss if visual inspections detect signs of corrosion. In addition, the response does not indicate whether the program will perform expanded visual inspections in other portions of the SWS if new degradation is detected in a SWS component. The applicant's basis also does not indicate the "acceptance criterion" that will be applied to a component's wall loss assessment if UT sizing measurements indicate that a corroded SWS piping or fitting component is thinning over time.

Request

Part 1 – Clarify whether the "monitoring and trending" element of the Open-Cycle Cooling Water Program will initiate subsequent UT monitoring activities (for wall thickness measurements) if corrosion (including RIC) is detected in either a lined or unlined SWS piping, and clarify whether this has been established in the plant procedures for implementing the visual examinations of the internal surfaces of the SWS piping under the Open-Cycle Cooling Water Program. If not, justify why the "monitoring and trending" element of the AMP would not initiate UT monitoring to quantify the degree of wall loss if corrosion (including RIC) is detected in a lined or unlined SWS piping component.

Part 2 – Clarify whether the implementation of the Open-Cooling Water Program will initiate expanded visual examinations to other portions of the SWS if corrosion (including RIC) is detected in a specific SWS piping or fitting location. If so, clarify and justify the sample expansion criteria that will be implemented in accordance with the AMP. Otherwise, justify the basis for omitting applicable sample expansion criteria in the AMP if sample expansion criteria are not included in the "detection of aging effects" or "monitoring and trending" element bases for the AMP. In addition, clarify and justify the "acceptance criterion" that will be used to initiate further corrective actions if corrosion (including RIC) is detected in a specific SWS

piping or fitting component and wall thinning of the component has been observed as part of the program's monitoring activities.

NextEra Energy Seabrook Response to RAI B.2.1.11-4

Response to Part 1

The Monitoring and Trending element of the Open-Cycle Cooling Water Program includes wall thickness measurements when any indication of base metal corrosion is observed. This requirement currently exists in the Station's "Service Water Inspection and Repair Trending" guideline. The Open-Cycle Cooling Water Program and the existing Station guideline also require trending of the wall thickness if internal coating is not repaired.

Response to Part 2

Due to recurring internal corrosion (RIC) of the Service Water (SW) piping, an expanded inspection and monitoring program has been put in place under the Monitoring and Trending element of the Open-Cycle Cooling Water Program. This expanded inspection and monitoring program exceeds the piping inspection guidelines provided in LR-ISG-2013-1 (e.g., 73, 1-foot axial length circumferential segments of piping or 50 percent of the total length of each coating/lining material and environment combination piping, whichever is less) and will remain in place until susceptible piping has been replaced with corrosion resistant material.

The vast majority of the Service Water (SW) piping is cement lined carbon steel piping. There are two redundant trains. Identical cement lining material is installed with the same fabrication and installation requirements in both trains. Both trains also have the same operating conditions.

As previously stated in SBK-L-14037, the maintenance strategy for the cement lined SW piping evolved from ultrasonic testing of the selected above ground locations to internal visual examinations. In 2006, ultrasonic testing of just above ground locations (mainly field welded locations) was determined to be ineffective in identifying areas of liner degradations and subsequent base metal corrosion. However, it was determined that identification of rust stains and corrosion nodules during internal pipe inspections was effective in identifying potential liner degradation and areas susceptible to corrosion and wall thinning.

The previous SW maintenance strategy had also not taken into consideration the liner degradation and wall thinning or leaks due to turbulent flow conditions. Following the 2011 root cause analysis previously described in SBK-L-14037, NextEra Energy Seabrook has taken an aggressive approach to internally inspect all of the above ground and underground cement lined SW piping within six refueling outages in order to identify and repair areas indicating liner degradation that may be susceptible to corrosion and wall thinning. These inspections were started in refueling outage 15 (September 2012) and will continue until such time that RIC is no longer a concern. Locations that are more susceptible to liner degradation and base metal corrosion have been taken into consideration in the inspection schedule. For example, above ground piping was determined to be more susceptible to areas of turbulent flow due to numerous butterfly valves, restricting orifices, and branch connections. Therefore, internal inspection of the above ground piping is scheduled to be completed within four refueling outages. The inspection of the SW buried piping, since it's less susceptible to turbulent flow conditions due to long straight lines, is scheduled to be completed within six refueling outages. To put the scope of internal inspections in perspective, there is approximately 2000 feet of SW above ground piping

and approximately 6000 feet of SW buried piping that is scheduled to be inspected within six refueling outages.

Also, there is an effort that is currently underway to replace the aboveground SW piping with corrosion resistant AL6XN material. Some of the above ground piping such as the SW piping associated with the Diesel Generator heat exchangers and some of the piping in the SW Pump House and Primary Auxiliary Building have already been replaced. Portions of other above ground SW piping are also scheduled to be replaced with AL6XN material during the next refueling outage (OR17/October 2015).

It should be noted that all the requirements of LR-ISG-2013-01 (Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers and Tanks) including "Detection of Aging Effects," "Monitoring and Trending", and "Acceptance Criteria" will be incorporated into the Open-Cycle Cooling Water Program as previously stated in SBK-L-14037 and as further clarified in Enclosure 2 of this letter. The baseline and subsequent coating/lining inspections, inspection intervals, extent of inspections, and representative sample inspections stated in LR-ISG-2013-01 will also be incorporated into the Open-Cycle Cooling Water Program. However, as described above, the extent of NextEra Energy Seabrook's internal inspections of the cement lined SW piping will significantly exceed those required in LR-ISG-2013-01 until such time recurring internal corrosion as defined LR-ISG-2012-02 has been eliminated. For example, instead of a representative sample size as described in LR-ISG-2013-01 (e.g., 73, 1-foot axial length circumferential segments of piping or 50 percent of the total length of each coating/lining material and environment combination piping, whichever is less), NextEra Energy will be internally inspecting all of the cement lined SW piping as described above.

It should also be noted that if a through wall leak is identified during plant operation, NextEra Energy Seabrook will follow Code Case N-513-3, which requires an extent of condition inspections of five additional susceptible/accessible locations. However, if: 1) a through wall leak or 2) reduction in wall thickness greater than the minimum required wall thickness, or 3) reduction in wall thickness greater than 50% of the nominal wall thickness as described in LR-ISG-2012-02 is identified during a refueling outage, the extent of condition inspections will be encompassed by the 500-1000 feet of inspections that will have been completed during that refueling outage, extensive inspections that have already been performed during the previous outages, and the extensive inspections that are scheduled for the future outages.

Management of the degradation/failure of cement lining in the SW system in accordance with the guidance provided in LR-ISG-2013-01 (Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers and Tanks) with augmented inspections described above provides reasonable assurance that recurring internal corrosion in the cement lined SW will be adequately managed.

Enclosure 2

Revision to the Aging Management of Loss of Internal Coating or Lining Integrity for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks provided in SBK-L-14037 dated March 3, 2014

As previously stated in SBK-L-14037 dated March 5, 2014 (Enclosure 2, Page 2 of 16, Paragraph 4), NextEra Energy Seabrook's Aging Management of Loss of Internal Coating or Lining Integrity for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks was based on draft LR-ISG-2013-01. The final LR-ISG-2013-01 has since been issued by the NRC (Reference 5). As a result, NextEra Energy Seabrook's program description previously provided in Enclosure 2 of SBK-L-14037 dated March 5, 2014 has been revised as follows to be consistent with the final LR-ISG-2013-01.

Item 5, starting on Page 11 of 16 of Enclosure 2, in SBK-L-14037 dated March 5, 2014 has been revised as follows:

5. In LRA Sections B.2.1.11, Open-Cycle Cooling Water System, B.2.1.16, Fire Water System, B.2.1.18, Fuel Oil Chemistry, and B.2.1.25, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, the following has been added to the end of the program descriptions as follows:

   Loss of Coating ***or Lining*** Integrity for ~~Service Level III (augmented)~~ Internal Coatings***/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks***:

   The program also manages loss of internal coating integrity due to blistering, cracking, flaking, peeling, or physical damage of ~~Service Level III (augmented)~~ internal coatings/***linings***.

   Definition of Internal ~~Service Level III (augmented)~~ Coatings***/Linings*** is as follows:

   All coatings applied to the internal surfaces of an in-scope component if its degradation could prevent satisfactory accomplishment of any of the functions identified under 10 CFR 54.4 (a)(1), (a)(2), or (a)(3). ***The definition of internal coatings/linings includes the following key aspects:*** ~~Service Level III (augmented) coatings are those:~~

a. Coatings/linings include paints, coatings, linings, and other items such as concrete surfaces and rubber or cementitious linings.

b. Coatings/linings can be constructed from inorganic (e.g., zinc-based, cementitious) or organic (e.g., elastomeric or polymeric) materials.

   ~~a. Used in areas outside of the reactor containment whose failure could adversely affect the safety function of a safety-related SSC or,~~

   ~~b. Applied to the internal surfaces of in-scope components and whose failure could prevent satisfactory accomplishment of any of the functions identified under 10 CFR 54.4 (a)(3).~~

   ~~The term "coating" includes inorganic (e.g., zinc-based) or organic (e.g., elastomeric or polymeric) coatings, linings (e.g., rubber, cementitious), and concrete surfaces that are designed to adhere to a component to protect its surface. The terms "paint" and "linings" are considered as coatings.~~

The program consists of periodic visual inspections of ~~Service Level III (augmented)~~ internal coatings/***linings*** and includes:

a. Baseline visual inspections of coatings/***linings*** installed on the interior surfaces of in-scope components will be conducted in the 10-year period prior to the period of extended operation.

b. Subsequent inspections are based on an evaluation of the effect of a coating failure on the in-scope component's intended function, potential problems identified during prior inspections, and known service life history. Subsequent inspection intervals are established by a coating specialist. Inspection intervals however, should not exceed those shown in the below table.

Inspection Intervals for Internal ~~Service Level III (augmented)~~ Coatings/***Linings*** for Tanks, Piping, and Heat Exchangers [1,6]	
Inspection Category[2]	Inspection Interval
A	6 years[3]
B[4,5]	4 years
~~C~~[5]	~~Inspections occur during the next 2 refueling outage intervals~~

1. Current licensing basis requirements (e.g. Generic Letter 89-13) might require more frequent inspections.

2. Inspection Categories

   A. No peeling, delamination, blisters, or rusting are observed during inspections. Any cracking and flaking has been found acceptable in accordance with the acceptance criteria. No ***cracking or*** spalling in cementitious coatings/***linings***.

   B. Prior inspection results do not meet Inspection Category A. However, a coating specialist has determined that no remediation is required.

   ~~C. Newly installed coatings or coatings that have been repaired or replaced.~~

3. If the following conditions are met, the inspection interval may be extended to 12 years:

   a. The identical coating/***lining*** material was installed with the same installation requirements in redundant trains with the same operating conditions and at least one of the trains is inspected every 6 years.

   b. The coating/***lining*** is not in a location subject to ***erosion that could result in mechanical damage to the coating/lining*** ~~turbulence~~ (e.g., piping downstream of a ***certain*** control valve).

4. ~~Specific locations that resulted in s~~***S***ubsequent inspections ~~being conducted to~~ ***for*** Inspection Category B ~~or C~~ are re-inspected ***at the original location(s)*** as well as ***inspections of*** new locations.

5. When conducting inspections to Inspection Category B, if two sequential subsequent inspections demonstrate no change in coating/***lining*** condition ***(i.e., at least three consecutive inspections with no change in condition)***, subsequent inspections ***at those locations*** may be conducted ***to Inspection Category A***~~at six-year intervals~~.
6. Internal inspection intervals for diesel fuel storage tanks may meet either this table or if the inspection results meet Inspection Category A.

c. The extent of inspections is based on an evaluation of the effect of a coating failure on the in-scope component's intended function, potential problems identified during prior inspections, and known service life history. Inspection locations are selected based on susceptibility to degradation and consequences of failure.

- All accessible internal coated surfaces of in-scope tanks and heat exchangers will be inspected.

- A representative sample of internally coated piping components not less than 73, 1-foot axial length circumferential segments of piping or 50% of the total length of each coating material and environment combination will be inspected. The inspection surface includes the entire inside surface of the 1-foot sample. If geometric limitations impede movement of remote or robotic inspection tools, the number of inspection segments is increased in order to cover an equivalent of 73, 1-foot axial length sections. For example, if the remote tool can only be maneuvered to view 1/3 of the inside surface, then 219 feet of pipe is inspected.

  Where documentation exists that manufacturer recommendations and industry consensus documents (i.e., those recommended in RG 1.54, or earlier versions of those standards) were complied with during installation, the extent of piping inspections may be reduced to the lesser of 25, 1-foot axial length circumferential segments of piping or 20 percent of the total length of each coating/lining material and environment combination.

  The above listed inspection of coatings may be omitted if the degradation of coatings cannot result in downstream effects such as reduction in flow, drop in pressure, or reduction in heat transfer for in-scope components. However, inspections are performed if corrosion rates or inspection intervals have been based on the integrity of the coatings. In this case, loss of coating integrity could result in unanticipated or accelerated corrosion rates of the base metal. Alternatively, if corrosion of the base material is the only issue related to coating degradation of the component, external wall thickness measurements can be performed to confirm the acceptability of the corrosion rate of the base metal.

d. Coatings specialists and inspectors will be qualified in accordance with ASTM International Standards ***endorsed in RG 1.54, Revision 2, as it pertains to the License***

Renewal in-scope components addressed by LR-ISG-2013-01 (Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks), except for cementitious materials. For cementitious coatings/linings inspectors should have a minimum of 5 years of experience inspecting or testing concrete structures or cementitious coatings/linings or a degree in the civil/structural discipline and a minimum of 1 year of experience.

e. ***Monitoring and Trending includes preparation of post inspection reports by the Coating Inspector or Coating Specialist. Reports prepared by the Coating Inspectors will be reviewed by the Coating Specialist.*** Monitoring and trending ***also*** includes pre-inspection reviews of the previous two inspection results and any subsequent repair activities. The review is performed by a coatings specialist and includes a list and location of all areas evidencing deterioration, a prioritization of the repair areas into areas that must be repaired before returning the system to service, areas where repair can be postponed to the next inspection, and, where possible, photographic evidence of inspection locations. When corrosion of the base material is the only issue related to coating degradation of the component, external wall thickness measurements can be used to in lieu of internal visual inspections of the coating and the corrosion rate of the base metal trended.

f. Acceptance criteria are as follows:

- Indications of peeling and delamination are not acceptable and the coatings are repaired or replaced. For coated surfaces that show evidence of delamination or peeling, physical testing is performed where physically possible. The test consists of destructive or nondestructive adhesion testing using ASTM International Standards. A minimum of three sample points adjacent to the defective area are tested.

- Blisters are evaluated by a coating specialist. However, physical testing is conducted to ensure that the blister is completely surrounded by sound coating bonded to the surface. If coatings are credited for corrosion prevention, the component's base material in the vicinity of the blister is inspected to determine if unanticipated corrosion has occurred. ***The potential effects of flow blockage and degradation of base material beneath a blister will also be considered in an accept-as-is disposition. Reasonable assurance that a coating will remain bonded to the substrate will be determined by the Coating Specialist based on ASTM D6677-07 "Standard Test Method for Evaluating Adhesion by Knife" with a rating of 6 or better or ASTM 4541-09 "Standard Test Method for Pull-Off Strength of Coatings Using Portable Adhesion Testers" with an adhesion of 200 psi or better.***

- Indications such as cracking, flaking, and rusting are to be evaluated by a coating specialist.

- Minor cracking and spalling of cementitious coatings is acceptable provided there is no evidence that the coating is debonding from the base material.

- As applicable, wall thickness measurements, ***projected to the next inspection,*** meet design minimum wall requirements.

- Adhesion testing results meet or exceed the degree of adhesion recommended in engineering documents specific to the coating and substrate.

g. ***Corrective actions for coatings/linings that do not meet acceptance criteria:***

Indications noted will be entered into the Seabrook Station Corrective Action Program for appropriate disposition.

Coatings/linings that do not meet acceptance criteria will be repaired, replaced, or removed. Testing or examination will be conducted to ensure that the extent of repaired or replaced coatings/linings encompasses sound coating/lining material.

As an alternative, coatings exhibiting indications of peeling and delamination may be returned to service if a) physical testing is conducted to ensure that the remaining coating is tightly bonded to the base metal, b) the potential for further degradation of the coating is minimized (i.e., any loose coating is removed, the edge of the remaining coating is feathered), c) adhesion testing using ASTM International standards endorsed in RG 1.54, Revision 2, is conducted at a minimum of 3 sample points adjacent to the defective area, d) an evaluation is conducted of the potential impact on the system, including degraded performance of downstream components due to flow blockage and loss of material of the coated component, and e) follow up visual inspections of the degraded coating are conducted within 2 years from detection of the degraded condition, with a re-inspection within an additional 2 years, or until the degraded coating is repaired or replaced.

If coatings/linings are credited for corrosion prevention and the base metal has been exposed or it is beneath a blister, the component's base material in the vicinity of the degraded coating/lining is examined to determine if the minimum wall thickness is met and will be met until the next inspection.

If a blister is not repaired, physical testing is conducted to ensure that the blister is completely surrounded by sound coating/lining bonded to the surface. Physical testing consists of adhesion testing using ASTM International standards endorsed in RG 1.54, Revision 2. Where adhesion testing is not possible due to physical constraints, another means of determining that the remaining coating/lining is tightly bonded to the base metal is conducted such as lightly tapping the coating/lining. Acceptance of a blister to remain in-service should be based both on the potential effects of flow blockage and degradation of the base material beneath the blister.

Item 7, on Page 14 of 16 of Enclosure 2, in SBK-L-14037 dated March 5, 2014 has been revised as follows:

7. In LRA Appendix B, Sections B.2.1.11, Open-Cycle Cooling Water System, B.2.1.16, Fire Water System, B.2.1.18, Fuel Oil Chemistry, ***and B.2.1.25, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components,*** the following new enhancement has been added to the enhancements section of the aging management programs:

   Enhancements

   Enhance the program to include visual inspection of ~~Service Level III (augmented)~~ internal ***coatings/linings*** for loss of coating integrity.

Item C, on Page 15 of 16 of Enclosure 2, in SBK-L-14037 dated March 5, 2014 has been revised as follows:

C. LRA Appendix A, Section A.2, Aging Management Programs, the program descriptions have been revised as follows:

   1. In LRA Section A.2.1.11, Open-Cycle Cooling Water System, the 1st paragraph has been revised as follows:

      The Open-Cycle Cooling Water System Program manages the aging effects of hardening and loss of strength, loss of material, reduction of heat transfer, and loss of coating integrity of ~~Service Level III (augmented)~~ internal coatings/***linings***.

   2. In LRA Section A.2.1.16, Fire Water System, the 1st paragraph has been revised as follows:

      The Fire Water System Program manages the aging effects of loss of material, and reduction of heat transfer due to fouling of the Fire Water System components through detailed inspections via the Seabrook Station Surveillance Test Procedures. The program also manages loss of coating integrity of ~~Service Level III (augmented)~~ internal coatings***/linings***.

   3. In LRA Section A.2.1.18, Fuel Oil Chemistry, the last paragraph has been revised as follows:

      Fuel Oil storage tanks are periodically drained and inspected. This inspection includes ultrasonic thickness measurements of the tank bottom surface to ensure that significant degradation has not occurred. The program also manages loss of coating integrity of ~~Service Level III (augmented)~~ internal coatings***/linings***.

4. In LRA Section A.2.1.25, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, the1st paragraph has been revised as follows:
   The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program manages the aging effects of cracking, loss of material, fouling, reduction of heat transfer, hardening and loss of strength, and loss of coating integrity of ~~Service Level III (augmented)~~ internal coatings*/linings*. This program consists of inspections of the internal surfaces of aluminum, CASS, copper alloy, copper alloy >15% zinc, elastomer, galvanized steel, gray cast iron, nickel alloy, stainless steel, and steel piping, piping components, ducting and other components that are not covered by other aging management programs.
5. ***In LRA Sections A.2.1.11 (Open-Cycle Cooling Water System), A.2.1.16 (Fire Water System), A.2.1.18 (Fuel Oil Chemistry), and A.2.1.25 (Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components), the following new paragraph has been added to the end of the program descriptions as follows:***

   The program also includes periodic visual inspections of all coatings/linings applied to the internal surfaces of in-scope components where loss of coating or lining integrity could impact the component's and downstream component's current licensing basis intended function. For coated/lined surfaces determined to not meet the acceptance criteria, physical testing is performed where physically possible (i.e., sufficient room to conduct testing) in conjunction with repair or replacement of the coating/lining. The training and qualification of individuals involved in coating/lining inspections of noncementitious coatings/linings are conducted in accordance with ASTM International Standards endorsed in RG 1.54, Revision 2, as it pertains to the License Renewal in-scope components addressed by LR-ISG-2013-01 (Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks). For cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces.

Item D, on Page 16 of 16 of Enclosure 2, in SBK-L-14037 dated March 5, 2014 has been revised as follows:

D. In LRA Appendix A, Section A.3, new commitments #79, #80, #81, and #82 have been added as follows:

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
79.	Open-Cycle Cooling Water System	Enhance the program to include visual inspection of ~~Service Level III (augmented)~~ internal coatings*/linings* for loss of coating integrity.	A.2.1.11	Within 10 years prior to the period of extended operation

80.	Fire Water System	Enhance the program to include visual inspection of ~~Service Level III (augmented)~~ internal coatings/***linings*** for loss of coating integrity.	A.2.1.16	Within 10 years prior to the period of extended operation
81.	Fuel Oil Chemistry	Enhance the program to include visual inspection of ~~Service Level III (augmented)~~ internal coatings/***linings*** for loss of coating integrity.	A.2.1.18	Within 10 years prior to the period of extended operation
82.	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Enhance the program to include visual inspection of ~~Service Level III (augmented)~~ internal coatings/***linings*** for loss of coating integrity.	A.2.1.25	Within 10 years prior to the period of extended operation

Enclosure 3

Revision to the Loss of Preload AMR Line Item for Diesel Generator Exhaust Manifold Flange Bolting Provided in the 4th Annual Update (SBK-L-14173 dated October 2, 2014)

Revision to the Loss of Preload AMR Line Item for Diesel Generator Exhaust Manifold Flange Bolting Provided in the 4th Annual Update (SBK-L-14173 dated October 2, 2014)

In Table 3.3.2-12, on Page 3.3-268, the Note for the new AMR line item that was added for the Nickel Alloy Diesel Generator exhaust manifold flange bolting has been changed from Note C (Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP) to Note F (Material not in NUREG-1801 for this component). Note F is a more appropriate "standard note" for this new AMR line item.

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	Pressure Boundary	Nickel Alloy	Air-Indoor Uncontrolled (External)	Loss of Preload	Bolting Integrity Program	None	None	~~C~~ ***F***

Enclosure 4

LRA Appendix A - Final Safety Analysis 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	Provide confirmation and acceptability of the implementation of MRP-227-A by addressing the plant-specific Applicant/Licensee Action Items outlined in section 4.2 of the NRC SER.	A.2.1.7	May 31, 2015
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.
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 (2011 Edition) 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 (2011 Edition).	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 to evaluate wall thickness and inner diameter of the fire protection piping ensuring that corrosion product buildup will not result in flow blockage due to fouling. Where surface irregularities are detected, follow-up volumetric examinations are performed. 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 ***1) In-scope outdoor tanks, except fire water storage tanks, constructed on soil or concrete, 2) Indoor large volume storage tanks (greater than 100,000 gallons) designed to near-atmospheric internal pressures, sit on concrete or soil, and exposed internally to water, 3) Visual, surface, and volumetric examinations of the outside and inside surfaces for managing the aging effects of loss of material and cracking, 4) External visual examinations to monitor degradation of the protective paint or coating, and 5) Inspection of sealant and caulking for degradation by performing visual and tactile examination (manual manipulation) consisting of pressing on the sealant or caulking to detect a reduction in the resiliency and pliability.*** ~~components and aging effects required by the Aboveground Steel Tanks and to perform visual, surface, and volumetric examinations of the outside and inside surfaces for managing the aging effects of loss of material and cracking.~~	A.2.1.17	Within 10 years prior to the period of extended operation.
13.	Fire Water System	Enhance the program to perform exterior inspection of the fire water storage tanks annually for signs of degradation and include an ultrasonic inspection and evaluation of the internal bottom surface of the two Fire Protection Water Storage Tanks per the guidance provided in NFPA 25 (2011 Edition).	A.2.1.16	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.
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.
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 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.

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.

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 SF6 Bus	Implement the 345 KV SF6 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.

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.

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 of the accessible areas of the containment liner plate in the vicinity of the moisture barrier for loss of material. Perform opportunistic UT of inaccessible areas.	A.2.1.27	Baseline inspections were completed during OR16. Repeat containment liner UT thickness examinations at intervals of no more than five (5) 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.

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 reactor 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.
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. The removed core will also be subjected to petrographic examination for concrete degradation due to ASR per ASTM Standard Practice C856.	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	Quarterly Preventive Maintenance Activity Implemented
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	Complete.
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. Testing will be performed to confirm that parameters being monitored and acceptance criteria used are appropriate to manage the effects of ASR.	A.2.1.31A	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.
73.	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Enhance the program to include performance of focused examinations to provide a representative sample of 20%, or a maximum of 25, of each identified material, environment, and aging effect combinations during each 10 year period in the period of extended operation.	A.2.1.25	Prior to entering the period of extended operation.

74.	Fire Water System	Enhance the program to perform sprinkler inspections annually per the guidance provided in NFPA 25 (2011 Edition). Inspection will ensure that sprinklers are free of corrosion, foreign materials, paint, and physical damage and installed in the proper orientation (e.g., upright, pendant, or sidewall). Any sprinkler that is painted, corroded, damaged, loaded, or in the improper orientation, and any glass bulb sprinkler where the bulb has emptied, will be evaluated for replacement.	A.2.1.16	***Prior to the period of extended operation.*** ~~Within ten years prior to the period of extended operation.~~
75.	Fire Water System	Enhance the program to conduct an inspection of piping and branch line conditions every 5 years by opening a flushing connection at the end of one main and by removing a sprinkler toward the end of one branch line for the purpose of inspecting for the presence of foreign organic and inorganic material per the guidance provided in NFPA 25 (2011 Edition).	A.2.1.16	***Prior to the period of extended operation.*** ~~Within ten years prior to the period of extended operation.~~
76.	Fire Water System	Enhance the Program to conduct the following activities annually per the guidance provided in NFPA 25 (2011 Edition). • main drain tests • deluge valve trip tests • fire water storage tank exterior surface inspections	A.2.1.16	***Prior to the period of extended operation.*** ~~Within ten years prior to the period of extended operation.~~
77.	Fire Water System	The Fire Water System Program will be enhanced to include the following requirements related to the main drain testing per the guidance provided in NFPA 25 (2011 Edition). • The requirement that if there is a 10 percent reduction in full flow pressure when compared to the original acceptance tests or previously performed tests, the cause of the reduction shall be identified and corrected if necessary. • Recording the time taken for the supply water pressure to return to the original static (nonflowing) pressure.	A.2.1.16	***Prior to the period of extended operation.*** ~~Within ten years prior to the period of extended operation.~~

78.	External Surfaces Monitoring	Enhance the program to include periodic inspections of in-scope insulated components for possible corrosion under insulation. ***A sample of outdoor component surfaces that are insulated and a sample of indoor insulated components exposed to condensation (due to the in-scope component being operated below the dew point), will be periodically inspected every 10 years during the period of extended operation.***	A.2.1.~~8~~***24***	Prior to the period of extended operation.
79.	Open-Cycle Cooling Water System	Enhance the program to include visual inspection of ~~Service Level III (augmented)~~ internal coatings/***linings*** for loss of coating integrity.	A.2.1.11	Within 10 years prior to the period of extended operation.
80.	Fire Water System	Enhance the program to include visual inspection of ~~Service Level III (augmented)~~ internal coatings/***linings*** for loss of coating integrity.	A.2.1.16	Within 10 years prior to the period of extended operation.
81.	Fuel Oil Chemistry	Enhance the program to include visual inspection of ~~Service Level III (augmented)~~ internal coatings/***linings*** for loss of coating integrity.	A.2.1.18	Within 10 years prior to the period of extended operation.
82.	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Enhance the program to include visual inspection of ~~Service Level III (augmented)~~ internal coatings/***linings*** for loss of coating integrity.	A.2.1.25	Within 10 years prior to the period of extended operation.

83.	Alkali-Silica Reaction Monitoring	Install instrumentation in representative sample areas of structures to monitor expansion due to alkali-silica reaction in the out-of-plane direction. Evaluate instrument and pin expansion data under the Operating Experience Element of the Alkali-Silica Reaction Monitoring Program to determine whether there is a need to enhance the program to monitor expansion in the out-of-plane direction. If the evaluation concludes that out-of-plane monitoring is necessary, establish acceptance criteria and monitoring frequencies for expansion in the out-of-plane direction using the instrument and pin expansion data.	A.2.1.31A	Prior to the period of extended operation.
84.	ASME Section XI, Subsection IWL	Evaluate the acceptability of inaccessible areas for structures within the scope of ASME Section XI, Subsection IWL Program.	A.2.1.28	Prior to the period of extended operation.
85.	***Fire Water System***	***Enhance the program to perform additional tests and inspections on the Fire Water Storage Tanks as specified in Section 9.2.7 of NFPA 25 (2011 Edition) in the event that it is required by Section 9.2.6.4, which states "Steel tanks exhibiting signs of interior pitting, corrosion, or failure of coating shall be tested in accordance with 9.2.7."***	***A.2.1.16***	***Prior to the period of extended operation.***
86.	***Fire Water System***	***Enhance the program to include disassembly, inspection, and cleaning of the mainline strainers every 5 years.***	***A.2.1.16***	***Prior to the period of extended operation.***
87.	***Fire Water System***	***Increase the frequency of the Open Head Spray Nozzle Air Flow Test from every 3 years to every refueling outage to be consistent with LR-ISG-2012-02, AMP XI.M27, Table 4a.***	***A.2.1.16***	***Prior to the period of extended operation.***
88.	***Fire Water System***	***Enhance the program to include verification that the drain holes associated with the transformer deluge system are draining to ensure complete drainage of the system after each test.***	***A.2.1.16***	***Within five years prior to the period of extended operation.***