NEXTera ENERGY SEABROOK

April 5, 2011

SBK-L-11062
Docket No. 50-443

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

Seabrook Station
Response to Request for Additional Information
NextEra Energy Seabrook License Renewal Application
Request for Additional Information – Set 11

References:

1. NextEra Energy Seabrook, LLC letter SBK-L-10077, "Seabrook Station Application for Renewed Operating License," May 25, 2010. (Accession Number ML101590099)
2. NRC Letter "Request for Additional Information Related to the Review of the Seabrook Station License Renewal Application (TAC NO. ME4028) – Request for Additional Information Set 11," March 7, 2011. (Accession Number ML110550920)
3. NextEra Energy Seabrook, LLC letter SBK-L-10179, "Supplement to the NextEra Energy Seabrook, LLC, Seabrook Station License Renewal Application", October 29, 2010. (Accession Number ML10306002)
4. NextEra Energy Seabrook, LLC letter SBK-L-11002, "Seabrook Station Response to Request for Additional Information, NextEra Energy Seabrook License Renewal Application Aging Management Programs – Set 4 ", January 13, 2011. (Accession Number ML110140809)
5. NextEra Energy Seabrook, LLC letter SBK-L-11003, "Seabrook Station Response to Request for Additional Information, NextEra Energy Seabrook License Renewal Application Aging Management Programs – Set 5 ", January 13, 2011. (Accession Number ML110140587)
6. NextEra Energy Seabrook, LLC letter SBK-L-11015, "Seabrook Station Response to Request for Additional Information, NextEra Energy Seabrook License Renewal Application – Sets 6, 7 and 8", February 3, 2011. (Accession Number ML110380081)

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

In Reference 2, the NRC requested additional information in order to complete its review of the License Renewal Application (LRA). Enclosure 1 contains NextEra's response to the request for additional information and associated changes made to the LRA. For clarity, deleted LRA text is highlighted by strikethroughs and inserted texts highlighted by bold italics. Enclosure 2 contains a technical evaluation associated with the RAI B.2.1.12-8 response.

Commitment numbers 63 and 64 are added to the License Renewal Commitment List. There are no other new or revised regulatory commitments contained in this letter. Enclosure 3 provides a revised LRA Appendix A - Final Safety Report Supplement Table A.3, License Renewal Commitment List, updated to reflect the license renewal commitment changes made in NextEra Energy Seabrook correspondence to date.

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

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

Sincerely,

NextEra Energy Seabrook, LLC.

Paul O. Freeman
Site Vice President

Enclosures:

Enclosure 1- Response to Request for Additional Information Seabrook Station License Renewal Application, Set # 11 and Associated LRA Changes

Enclosure 2- Chemistry Control in the Seabrook Thermal Barrier Loop

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

cc:

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Seabrook Station
Response to Request for Additional Information
NextEra Energy Seabrook License Renewal Application
Request for Additional Information – Set 11

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NEXTera ENERGY SEABROOK

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

Sworn and Subscribed

Before me this

5th day of April, 2011

Paul O. Freeman
Site Vice President

Shirley Sweeney
Notary Public

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

Enclosure 1 to SBK-L-11062

Response to Request for Additional Information

Seabrook Station License Renewal Application

Set 11 and Associated LRA Changes

Request for Additional Information (RAI) 3.2.2.2.6-02

Background:

By letter dated January 5, 2011, the staff issued request for additional information (RAI) 3.2.2.2.6-01 concerning aging management of stainless steel miniflow orifices in the chemical and volume control system. In its response dated February 3, 2011, NextEra Energy Seabrook, LLC (the applicant) modified its approach by proposing to credit only the Water Chemistry Program for aging management of the subject components. The applicant stated that the Water Chemistry Program is expected to mitigate the potential for erosion in the miniflow orifices by controlling the buildup of corrosion products and particulates that could contribute to erosion. The applicant also included a discussion of quarterly inservice testing required by its technical specifications and trending of the test data by a system engineer. Based on the information provided, the applicant changed Table 3.3.2-3, for the applicable orifice, to state that the Water Chemistry Program will be used to manage this aging effect, and the applicant added plant-specific note 8 with the comparable information.

Issue:

Standard Review Plan -License Renewal (SRP-LR) Section 3.2.2.2.6 states that loss of material due to erosion could occur in the stainless steel high pressure safety injection (HPSI) pump miniflow recirculation orifice exposed to treated borated water and recommends a plant-specific aging management program (AMP) be evaluated for erosion of the orifice due to extended use of the centrifugal HPSI pump for normal charging. The staff noted that the stainless steel miniflow orifices in the applicant's chemical and volume control system are functionally equivalent to, and in the same environment as the miniflow orifices described in SRP-LR Section 3.2.2.2.6; and they would be subject to the same aging effect.

SRP-LR, Appendix A, Section A.1.2.3.4, states that in a plant-specific AMP, the detection of aging effects should occur before there is a loss of intended function(s). The staff noted that the Water Chemistry Program does not include an inspection or testing activity to detect loss of material due to erosion in the stainless steel miniflow orifices in the chemical and volume control system. The staff also noted that the Generic Aging Lessons Learned (GALL) Report typically recommends using the One-Time Inspection Program to confirm effectiveness of the Water Chemistry Program to mitigate loss of material. Because the applicant has not credited any activity to confirm the Water Chemistry Program's effectiveness to mitigate erosion, the staff does not have sufficient information to conclude that the Water Chemistry Program will provide adequate aging management for the subject miniflow orifices.

Request:

Describe how the existing Water Chemistry Program is capable of detecting the loss of material due to erosion in the stainless steel miniflow orifices, or include in the AMP(s) for these components an inspection or testing activity that is capable of detecting the loss of material due to erosion before the loss of the components' intended function occurs.

NextEra Energy Seabrook Response:

To confirm the Water Chemistry Program's effectiveness, Seabrook Station will credit its Technical Specification performance monitoring program for the High Pressure Safety Injection Pump (CVCS Charging Pump) to detect loss of material due to erosion in the miniflow orifice. Seabrook Station Technical Specification 4.5.2.f (Emergency Core Cooling Systems – Surveillance Requirements) requires quarterly testing of the CVCS Charging Pumps. The pump is always tested in the same lineup where the flow path is only through the miniflow orifice. Pump flow and differential pressure are measured and recorded and compared to the acceptance criteria. If the acceptance criteria are not met (for flow or differential pressure) through the mini flow orifice, then the pump would be declared inoperable and the Technical Specification Limited Condition for Operation would be entered. Increased flow through the minimum recirculation flow line may be an indication of loss of material due to erosion of the miniflow orifice. If the miniflow orifice would experience erosion to the extent that the acceptance criteria for high flow is not met, then restoration of the pump to operable status would require appropriate corrective actions per the corrective action program.

Seabrook Station's approach is consistent with Branch Technical Position RLSB-1, Section A.1.1, which states that performance monitoring is one of four acceptable aging management programs (the other three being prevention, mitigation, and condition monitoring programs).

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

1. Plant specific note 8 for Table 3.3.2-3, as submitted in response to RAI 3.2.2.2.6-01 (SBK-L-11015 (Reference 6) dated February 3, 2011, Enclosure 1, page 74 of 92) is revised as follows:

   8 NUREG-1801 specifies a plant-specific program for this line item. The Water Chemistry Program will be used to manage the aging effect(s) applicable to this component type, material, and environment combination. ***To confirm the Water Chemistry Program's effectiveness to mitigate erosion, Technical Specification performance monitoring program for the CVCS Charging Pump will be credited. Performance testing of the pump measures the recirculation flow through the orifice and compares it to the acceptance criteria. Degradation of the orifice will be identified by the pump performance testing.***

2. Section 3.2.2.2.6, as submitted in response to 3.2.2.2.6-01 (SBK-L-11015 dated February 3, 2011(Reference 6), Enclosure 1, page 72 of 92), the following is added to the end of the 2nd paragraph as follows:

"Seabrook will use Water Chemistry Program, B.2.1.2, to manage loss of material due to erosion of the stainless steel high pressure pump mini-flow orifice in the Chemical and Volume Control System. The Water Chemistry Program is described in Appendix B. ***To confirm the Water Chemistry Program's effectiveness, Seabrook Station will credit its Technical Specification performance monitoring program for the High Pressure Safety Injection Pump (CVCS Charging Pump) to detect loss of material due to erosion in the miniflow orifice. Seabrook Station Technical Specification 4.5.2.f (Emergency Core Cooling Systems – Surveillance Requirements) requires quarterly testing of the CVCS Charging Pumps. The pump is always tested in the same lineup where the flow path is only through the miniflow orifice. Pump flow and differential pressure are measured and recorded and compared to the acceptance criteria. If the acceptance criteria is not met (for flow or differential pressure), then the pump would be declared inoperable and the Technical Specification Limited Condition for Operation would be entered. Increased flow through the minimum recirculation flow line may be an indication of loss of material due to erosion of the piping components in the flow path including the orifice. Restoration of the pump to operable status would require appropriate corrective actions per the corrective action program."***

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

NO.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
63	***Flow Induced Erosion***	***Ensure that the quarterly CVCS Charging Pump testing is continued during the PEO. Additionally, add a precaution to the test procedure to state that an increase in the CVCS Charging Pump mini flow above the acceptance criteria may be indicative of erosion of the mini flow orifice as described in LER 50-275/94-023.***	***N/A***	***Prior to the period of extended operation***

Request for Additional Information (RAI) B.2.1.12-8

Background:

The closed-cycle water chemistry guidelines in Electric Power Research Institute (EPRI) topical report (TR) TR-107396 state that higher levels of hydrazine can increase ammonia levels. Elevated concentrations of ammonia can cause higher levels of corrosion or cracking of copper alloys. The EPRI guideline also states that higher sulfate levels can lead to stress-corrosion cracking of stainless steel alloys. By letter dated January 13, 2011, the staff issued RAI B.2.1.12-1, in which the staff requested additional information on the effect of hydrazine and sulfate excursions in the thermal barrier system for aging during the period of extended operation. The response to RAI B.2.1.12-1 stated that the applicant evaluated the significance of allowing operation of the thermal barrier system at the elevated hydrazine and sulfate levels, and determined it to be acceptable. The response also stated that routine monitoring during operation at the elevated ranges showed no indication of system or component degradation.

Issue:

The applicant did not provide details of its evaluation that determined the operation at the elevated levels of hydrazine and sulfate would not cause any accelerated aging that could affect components during the period of extended operation. In addition, the applicant did not describe the routine monitoring it had performed during operation at the elevated ranges that could be credited for showing that no system or component degradation had occurred.

Request:

Provide the technical information that describes why the elevated levels of hydrazine and sulfate will not have caused accelerated aging of the components in the thermal barrier system that could affect component functions during the period of extended operation. If it is determined that the elevated levels of hydrazine and sulfate may have caused some accelerated aging, provide information on the AMP that will be used to manage the accelerated aging.

NextEra Energy Seabrook Response:

In response to this RAI, a new evaluation was performed to determine if accelerated aging of the components would occur due to elevated hydrazine and sulfate levels in the thermal barrier (TB) system.. This new evaluation included review of the Seabrook Station Chemistry Study/Technical Information Document (CHSTID) "Evaluation of Sulfate Concentration in Thermal Barrier Closed Cooling Loop" dated December 2004, referenced in the Closed Cycle Cooling Water System AMP and in the response to RAI B.2.1.12-1 provided in SBK-L-11002, dated January 13, 2011 (Reference 4).

This new evaluation dated March 28, 2011 is included as Enclosure 2 to this letter. In summary, conclusions are as follows:

> "There is no reason to expect that increased carbon steel or stainless steel corrosion rates occurred from 1999 to 2009 when hydrazine and sulfate concentrations were elevated in the Seabrook TB system. The elevated hydrazine concentrations would be expected to lead to minimum oxygen concentrations in the bulk water and very low electrochemical potentials of the stainless steel surfaces resulting in a minimum tendency for stress corrosion cracking. Sulfate, in the concentration range that was observed, is not expected to be a significant accelerant of SCC of stainless steel at TB system temperatures particularly at the low electrochemical potential of the stainless steel materials at the high hydrazine to oxygen concentration ratio".

Based on the conclusions of this evaluation, Seabrook Station maintains that the effects of the elevated hydrazine and sulfate levels are insignificant and will not have caused accelerated aging of the components in the thermal barrier system that could affect component functions during the period of extended operation.

As previously stated in response to RAI B.2.1.12-1, Seabrook Station had returned hydrazine and sulfate operating levels to within those recommended in the EPRI Guidelines in early 2010. The Seabrook Station Closed Cooling Water Chemistry Control program has also been revised to reflect those levels in the appropriate sampling schedule.

Request for Additional Information (RAI) 4.7.12-2

Background:

By letter dated January 5, 2011, the staff issued RAI 4.7.12-1 concerning license renewal application (LRA) Section 4.7.12, which discussed the absence of a time-limited aging analysis (TLAA) for metal corrosion allowances. In its response dated February 3, 2011, the applicant revised LRA Section 4.7.12 to include steam generator tube metal corrosion allowance as a TLAA and revised Tables 4.1-1 and 4.1-2 for the disposition method and applicability of the TLAA. However, LRA Section 4.7.12 now states that the TLAA disposition for this issue is in accordance with 10 CFR 54.21 (c)(1)(iii), whereas the revision to Table 4.1-1 states that the TLAA disposition is in accordance with 10 CFR 54.21 (c)(1)(i). In addition, the staff noted that the final safety analysis report (FSAR) supplement in LRA Section A.2.4.5, "Other Plant-Specific TLAAs," had not been revised as a result of this new determination.

Issue:

SRP-LR Section 4.7.3.1.1, "10 CFR 54.21 (c)(1)(i)," states that the justification provided by the applicant is reviewed to verify that the existing analyses are valid for the period of extended operation. In contrast, SRP-LR Section 4.7.3.1.3, "10 CFR 54.21(c)(1)(iii)," states that the applicant's proposal to manage the aging effects associated with the TLAA by an AMP is reviewed to verify that the effects of aging will be adequately managed. The staff is unclear which method was used by the applicant. In addition, 10 CFR 54.21(d) states that the FSAR supplement must contain a summary description of the evaluation of TLAAs for the period of extended operation as part of the LRA.

Request:

a) Clarify which method was used to disposition the TLAA associated with the steam generator tube metal corrosion allowance.

b) Provide a revised FSAR supplement for the evaluation of the TLAA associated with the steam generator tube metal corrosion allowance, in accordance with 10 CFR 54.21 (d).

NextEra Energy Seabrook Response:

a) In response letter, SBK-L-11015 (Reference 6); NextEra incorrectly listed the disposition as Aging Management, 10 CFR 54.21(c)(1)(iii). The correct disposition is Validation, 10 CFR 54.21(c)(1)(i) as the analyses remains valid for the period of extended operation.

1. In LRA Section 4.7.12, page 4.7-13, the disposition previously provided in SBK-L-11015 (Reference 6) should be revised as follows:

~~Aging Management, 10 CFR 54.21(c)(1)(iii) The effects of aging on theintended function(s) will be adequately managed for the period of extended operation by the Steam Generator Tube Integrity Program (B.2.1.10), which manages the aging effects of loss of material due to wall thinning from flow accelerated corrosion of the Steam Generator components.~~

Disposition

Validation, 10 CFR 54.21(c)(1)(i) – The analyses remain valid for the period of extended operation.

b) The following UFSAR supplement is provided regarding the TLAA associated with the steam generator tube metal corrosion allowance.

1. In LRA Appendix A, a new section A.2.4.5.11 is provided as follows:

A.2.4.5.11 METAL CORROSION ALLOWANCES AND CORROSION EFFECTS

The Seabrook Station licensing basis assumes a general corrosion and erosion rate of 3 mils is for the steam generator tube wall. The corrosion rate is based on a conservative weight loss rate of Inconel tubing in flowing 650°F primary side reactor coolant fluid. The weight loss, when equated to a thinning rate and projected over a 40-year design operating objective, with appropriate reduction after initial hours, is equivalent to 0.083 mils thinning. A linear projection of this thinning rate to a 60-year period is equivalent to 0.1245 mils thinning. This linear projection to 60 years is considered to be conservative because it includes in the base rate the higher rate during the initial hours. The assumed corrosion rate of 3 mils leaves a conservative 2.8755 mils for general corrosion thinning on the secondary side.

The analyses will remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

Request for Additional Information (RAI) 3.4.1-37-2

Background:

By letter dated January 5, 2011, the staff issued RAI 3.4.1-37-1. This RAI requested information as follows: a) propose to manage aging of these components using water chemistry and an appropriate verification AMP as indicated by the GALL Report for the management of aging in a secondary feedwater/steam environment or justify why the use of a verification AMP is either inconsistent with the GALL Report or technically unnecessary; b) justify why is it unnecessary to consider both the aging effects "loss of material" and "cracking" for each of the components under consideration; c) classify the steam generator feedwater inlet ring (J tube) and the steam generator tubes as steam generator components (making the appropriate verification AMP the Steam Generator Tube Integrity Program) or justify why these components should be considered piping, piping components, or piping elements as proposed by item 3.4.1-37. The applicant responded to this RAI by letter dated February 3, 2011. With one potential exception, the staff found these responses acceptable.

Issue:

In its response to the previous RAI, the applicant reclassified the steam generator feedwater nozzle (thermal sleeve) and the orifice from being consistent with SRP-LR Table 3.4.1-34 (generic note A) to being inconsistent with the GALL Report (generic note H). The applicant also proposed to manage the aging of these components through the use of its Water Chemistry Program. Based on its review, it appears to the staff that the components, materials, environments, and aging effects under consideration are described by SRP-LR Table 3.4-1 ID 84. The staff notes that SRP-LR Table 3.4-1 ID 84, recommends that aging be managed through the use of GALL Report AMP XI.M2, Water Chemistry and either AMP XI.M32, One-Time Inspection, or AMP XI.M1, ASME Section XI, Inservice Inspection.

The staff notes that, in its response to the previous RAI, the applicant stated that these components were not available for inspection. The staff also notes that these components have been addressed in many recent license renewal Safety Evaluation Reports (SERs). While there have been differences in the approaches to the management of aging of these components from plant to plant, in each case the SER indicates that the accepted method of aging management involves the use of an AMP to manage water chemistry and an AMP to perform at least a one-time inspection to verify the efficacy of the water chemistry program. This indicates to the staff that water chemistry and inspection programs are necessary for adequate aging management and that these components are generally inspectable.

Request:

Please: a) demonstrate why the aging management guidance provided by SRP-LR Table 3.4-1 ID 84 need not be followed; or b} demonstrate why the components under consideration are not inspectable; or c) propose to manage aging of these components in a manner consistent with or equivalent to SRP-LR Table 3.4-1 ID 84.

NextEra Energy Seabrook Response:

a) The aging management guidance provided in NUREG-1800, Table 3.1-1, ID 84, refers to R-36, which is associated with NUREG-1801 line item IV.D2-9. This line item is associated with once-through type steam generators as found in Babcock & Wilcox pressurized water reactors as described in NUREG-1801, Chapter IV.D2. Seabrook Station has recirculating-type steam generators as found in Westinghouse pressurized water reactors. Therefore, Chapter IV.D1 of NUREG-1801 was utilized instead of Chapter IV.D2.

   In Chapter IV.D1 of NUREG-1801 [Steam Generators (Recirculating)], nickel alloy steam generator components such as the secondary side nozzles, vent, drain, and instrumentation lines are not identified as being susceptible to cracking due to stress corrosion cracking in secondary feedwater/steam environment and therefore, has no corresponding line item in Chapter IV.D1. Hence, the reason why generic note H was utilized instead of generic note A.

b) <u>Inspectability of the Steam Generator Steam Flow Restricting Orifice and Feedwater Nozzle (Thermal Sleeve)</u>

   <u>Inspectability of the Steam Generator Steam Flow Restricting Orifice</u>

   Seabrook USFAR, Section 5.4.4 describes the steam generator steam flow restricting orifice as follows:

   > "The flow restrictor consists of seven Inconel (ASME SB-163) venturi inserts which are inserted into the holes in an integral steam outlet nozzle forging. The inserts are arranged with one venturi at the centerline of the outlet nozzle and the other six equally spaced around it. After insertion into the nozzle forging holes, the Inconel venturi inserts are welded to the Inconel cladding on the inner surface of the forgings.
   >
   > The flow restrictor design has been sufficiently analyzed to assure its structural adequacy. The equivalent throat diameter of the steam generator outlet is 16 inches, and the resultant pressure drop through the restrictor at 100 percent steam flow is approximately 3.28 psi. This is based on a design flow rate of 4.135×10^6 lb/hr. Materials of construction and manufacturing of the flow restrictor are in accordance with Section III of the ASME Code.

Since the restrictor is not a part of the steam system boundary, no tests and inspection beyond those during fabrication are anticipated."

The steam generator steam flow restricting orifices are located above the steam generator upper deck plates and do not have manways or an access points to allow for the inspection of the orifices. Therefore, the steam flow restricting orifice is not accessible for visual inspections (direct visual or remote visual) without a plant modification.

Inspectability of the Steam Generator Feedwater Nozzle (Thermal Sleeve)

The Steam Generator Feedwater Nozzle (Thermal Sleeve) is an integral part of the steam generator feedwater ring and is not accessible for direct visual inspections. However, upon further discussion with the Seabrook Station Steam Generator Tube Integrity Program owner, a remote visual inspection of the feedwater nozzle (thermal sleeve) is feasible by means of entering the feedwater ring via the feedwater ring J tube opening.

c) Aging Management of the Steam Generator Steam Flow Restricting Orifice and Feedwater Nozzle (Thermal Sleeve)

Aging Management of the Steam Generator Steam Flow Restricting Orifice

Plant or industry operating experience has not identified any aging effects associated with the steam generator steam flow restricting orifices. Additionally, EPRI Steam Generator Integrity Assessment Guidelines (EPRI 1012987 Rev. 2) has not identified the steam generator steam flow restricting orifices as one of the components requiring inspection. Therefore, verification of the Water Chemistry Program is not needed to provide reasonable assurance that the steam generator steam flow restricting orifice will perform such that the intended functions are maintained consistent with the current licensing basis during the period of extended operation.

Aging Management of the Feedwater Nozzle (Thermal Sleeve)

Although there is currently no plant/industry operating experience and no EPRI requirement or recommendation that warrants inspection of the steam generator feedwater nozzles (thermal sleeves), Seabrook Station will include inspection of the feedwater nozzles (thermal sleeves) under the Steam Generator Tube Integrity Program to verify the effectiveness of the Water Chemistry program.

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

1. Item 8, on page 83 of 92 of Enclosure 1, as submitted in SBK-L-11015 dated February 3, 2011 (Reference 6), is revised as follows:

Steam Generator Feedwater Nozzle (Thermal Sleeve)	Pressure Boundary	Nickel Alloy	Secondary Feedwater/Steam (External)	Cracking	Water Chemistry Program ***Steam Generator Tube Integrity Program***	None	None	H,~~10~~ ***9***
Steam Generator Feedwater Nozzle (Thermal Sleeve)	Pressure Boundary	Nickel Alloy	Secondary Feedwater/Steam (Internal)	Cracking	Water Chemistry Program ***Steam Generator Tube Integrity Program***	None	None	H,~~10~~ 9

2. Item 9, on page 84 of 92 of Enclosure 1, as submitted in SBK-L-11015 dated February 3, 2011 (Reference 6), is revised as follows:

Steam Generator Feedwater Nozzle (Thermal Sleeve)	Pressure Boundary	Nickel Alloy	Secondary Feedwater/Steam (External)	Loss of Material	Water Chemistry Program ***Steam Generator Tube Integrity Program***	None	None	H,~~11~~ ***8***
Steam Generator Feedwater Nozzle (Thermal Sleeve)	Pressure Boundary	Nickel Alloy	Secondary Feedwater/Steam (Internal)	Loss of Material	Water Chemistry Program ***Steam Generator Tube Integrity Program***	None	None	H,~~11~~ ***8***

Request for Additional Information (RAI) B.2.1.22-1

Background:

The applicant's response to RAI B.2.1.22-1, by letter dated January 13, 2011, was not sufficient to resolve all of the staff's questions.

Issue:

a) Although the applicant will be sampling for several different factors (e.g., soil resistivity, water samples) it is not clear to the staff that the stated parameters are sufficient, nor how the results will be combined to determine the level of soil corrosivity such as can be determined by using American Water Works Association C105/A2.15-10 Table A.1.

b) The applicant's program only increases the number of planned inspections based on the quality of backfill in the vicinity of the buried pipe. Given that portions of buried in-scope steel piping are not provided with cathodic protection, the staff believes that the number of inspections of this piping should also be informed by localized soil conditions.

c) Given that localized soil conditions can vary, the applicant's response was not clear enough for the staff to conclude that soil samples will be obtained in the vicinity of each buried in-scope steel piping system (excluding fire protection) that is not provided cathodic protection.

d) It is not clear to the staff how often soil samples will be obtained during the period of extended operation.

Request:

a) State what soil parameters will be utilized and how their aggregate impact will be evaluated to determine localized soil corrosivity.

b) State whether localized soil conditions will be utilized to increase the number of inspections or state how there will be reasonable assurance that the piping system's current licensing basis function(s) will be maintained without increasing the number of samples in the absence of localized soil data or with results that indicate that the soil is corrosive.

c) State if soil samples will be obtained in the local vicinity of all buried in-scope steel piping systems (excluding fire protection) that are not provided with cathodic protection.

d) State how often soil sampling will be conducted during the period of extended operation, or if soil samples will not be collected during the period of extended operation, state how it is known that localized soil conditions will not vary with time.

NextEra Energy Seabrook Response:

a) To provide additional assurance that the piping will remain capable of performing its intended function, soil will be sampled prior to the period of extended operation (PEO) to confirm that the soil conditions are not corrosive. The number of inspections performed during the PEO will be based on the results of this soil survey. The parameters monitored will be utilized to obtain a comparative corrosion index (corrosivity) for the non-cathodically protected steel piping within the systems monitored. Corrosivity will be determined using established soil analysis methodology such as EPRI Report 1021470, "Balance of Plant Corrosion - The Buried Pipe Reference Guide", Chapter 8, "Soil Analysis." The EPRI report arrives at a corrosion index using combined values for soil resistivity, pH, redox potential, sulfides, and moisture in accordance with American Water Works Association standard C105, and considers the soil to be corrosive if the combined value is greater than 10. Table 8-1 of the EPRI report is titled "AWWA C105 soil corrosivity index" and mirrors the parameters, values and points shown in the AWWA standard.

b) As described in item a. above, soil will be sampled prior to the period of extended operation (PEO) to confirm that the soil conditions are not corrosive. The number of inspections during the PEO will be based on the results of this soil survey. If soil analysis indicates that the soil is corrosive, the number of inspections for non-cathodically protected steel pipe shall be increased from 4 to 6 for non-HAZMAT piping and from 5% to 7½% for HAZMAT piping during the PEO.

c) Soil samples will be taken at a minimum of two locations in the vicinity of in-scope, non-cathodically protected steel piping to obtain representative soil conditions for each system, excluding fire protection.

d) Soil will be sampled prior to the PEO to confirm that the soil conditions are not corrosive. If the initial survey shows the soil to be non-corrosive, additional soil samples will be taken at least once every 10 years thereafter, during the PEO, to confirm the initial sample results.

Based on the above discussion, the LRA is revised to incorporate soil sampling and analyses as a preventive action and a factor in determining the scope of buried pipe inspections during the PEO as follows:

1. Section A.2.1.22, as submitted in SBK-L-10179 Supplement 1 dated October 29, 2010 (Reference 3), in Enclosure 1, on page 3 of 18, the1st paragraph of program description is revised as follows:

> "The Buried Piping and Tanks Inspection Program manages loss of material from the external surfaces of buried, underground, and inaccessible submerged steel, stainless steel, and polymer piping and components. The plant has no buried tanks in scope for license renewal. Depending on the material, the program includes external coatings, cathodic protection, ***analyses for soil corrosivity,*** and quality of backfill as preventive measures to mitigate corrosion."

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

NO.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
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.***

3. In Section B.2.1.22, as submitted in Supplement 1, dated October 29, 2010 (SBK-L-10179), in Enclosure 1, on page 4 of 18, the 2nd paragraph of Program Description is revised as follows:

    The Seabrook Station program will include coating, cathodic protection and backfill quality as preventive measures to mitigate corrosion, and periodic inspections that manage the aging effects of corrosion on buried piping in the scope for license renewal. ***Soil analyses will be performed to determine the corrosivity of the soil near non-cathodically protected steel pipe. The corrosivity of the soil will be used as a factor in determining the number of locations or percentage of piping to be inspected for non-cathodically protected steel piping.***

4. In Section B.2.1.22, as submitted in License Renewal Application Supplement 1, dated October 29, 2010 (SBK-L-10179), in Enclosure 1, Element 4 – Detection of Aging Effects, on page 11 of 18, the following paragraph is added after the 1st full paragraph as follows:

    Soil samples will be taken prior to entering the period of extended operation (PEO) to confirm that the soil conditions are not corrosive. The corrosivity of the soil will be used as a factor in determining the number of locations or percentage of piping to be inspected for non-cathodically protected steel piping. . If the initial survey shows the soil to be non-corrosive, additional soil samples will be taken at least once every 10 years during the PEO to confirm the initial sample results. Soil samples will be taken at a minimum of two locations in the vicinity of in-scope, non-cathodically protected steel piping to obtain representative soil conditions for each system (except for Fire Protection if the integrity of that system is monitored by jockey pump performance). The parameters monitored will be utilized to obtain a comparative corrosion index (corrosivity) for the piping within the systems monitored. Corrosivity will be determined using established soil analysis

methodology such as EPRI Report 1021470, "Balance of Plant Corrosion - The Buried Pipe Reference Guide", Chapter 8, "Soil Analysis." The EPRI report arrives at a corrosion index using combined values for soil resistivity, pH, redox potential, sulfides, and moisture in accordance with American Water Works Association standard C105, and considers the soil to be corrosive if the combined value is greater than 10.

5. In Section B.2.1.22, as submitted in License Renewal Application Supplement 1, dated October 29, 2010 (SBK-L-10179), in Enclosure 1, Element 4 – Detection of Aging Effects, on page 12 of 18, the Buried Piping Inspections Locations table is revised as follows:

Material Type	System	HAZMAT	Cathodically Protected	Applied Coatings	Inspections per 10-Year Period[1,2,3]	
					Adequate Backfill[4]	Inadequate Backfill[4]
Steel	CBA, IA, FP, SW	No	Yes	Yes	1	4
	AB[5]	Yes	No	Yes	***Non-corrosive soil 5%*** ***Corrosive soil [6] 7½%***	10%
	CBA, CO, DG, FW, DF, FP	No	No	Yes	***Non-corrosive soil 4*** ***Corrosive soil [6,7] 6***	8
Polymer	FP	No	No	No	1	2
Stainless Steel	DG	Yes	Yes	Yes	1	1
	CO	No	No	Yes		

GENERAL NOTES:

1. Each inspection will examine either the entire length of a run of pipe or a minimum of 10 feet.
2. If the length of pipe to be inspected based on the number of inspections times the minimum inspection length (10 feet) exceeds 10% of the length of the piping under consideration, only 10% need be inspected.
3. If the length of pipe to be inspected based on the total length of pipe under consideration times percentage to be inspected is less than 10 feet, either 10 feet or the total length of pipe present, whichever is less, will be inspected.
4. The effectiveness of backfill materials and processes will be determined by the condition of coatings and base materials noted during inspections. If damage to the coatings or base materials are determined to have been caused by the backfill, the backfill will be considered to be "inadequate" (for the purpose of this program).
5. This line is not is use. It has been drained and flushed and is awaiting replacement per EC 12681. The inspection criteria for the replacement piping will be determined based material selection, coating, cathodic protection, and quality of backfill.
6. ***Soil corrosivity is determined by soil analysis using a demonstrated methodology such as EPRI report 1021470, Table 8-1. A value greater than 10 using this method is considered corrosive. The number of inspections for non-cathodically protected steel piping in corrosive soil apply only to the inspections performed during the period of extended operation.***
7. ***If monitoring of jockey pump activity is credited for verification of fire protection piping integrity, soil samples in the vicinity of the fire protection piping is not required.***

6. In Section B.2.1.22, as submitted in License Renewal Application Supplement 1, dated October 29, 2010 (SBK-L-10179), on Enclosure 1, on page 13 of 18, the following paragraph is added after the 2nd paragraph of Element 5 - Monitoring And Trending:

   For in-scope steel piping not protected by cathodic protection, where initial surveys have shown the soil to be non-corrosive, soil analyses will be performed at least once every 10 years to confirm whether or not the soil in the area of this piping is corrosive. Soil corrosivity is used as one factor in determining the number of locations or percentage of piping to be inspected during the period of extended operation.

7. In Section B.2.1.22, as submitted in License Renewal Application Supplement 1, dated October 29, 2010 (SBK-L-10179), in Enclosure 1, on page 14 of 18, the following paragraph is added following the 4th paragraph of Element 6 - Acceptance Criteria:

   Soil corrosivity is determined by soil analysis. If the calculated corrosion index value is greater than 10 points (i.e., corrosive soil) the inspection locations for non-cathodically protected steel piping are increased as shown in Element 4 - Detection of Aging Effects.

Request for Additional Information (RAI) B.2.1.22-3

Background:

The applicant's response to RAI B.2.1.22-3, by letter dated January 13, 2011, was not sufficient to resolve all of the staff's questions.

Issue:

The applicant stated that it utilized a Keeler and Long 1000 Kolormastic system and Tapecoat 20 primer and wrap when installing flanges to allow access to the underground service water piping that is exposed to raw water. The applicant also stated that the painting system chosen for the piping is designed to protect the pipe from long term external corrosion when exposed to continuous immersion in brackish stagnant water. The staff does not have sufficient information related to this coating to independently determine that it will provide protection to the piping when exposed to long term immersion.

Request:

Provide copies of the vendor technical data that demonstrated that the coating system was acceptable for long term immersion in a brackish water environment. Alternatively, if the vendor information is proprietary, provide a copy of the applicable portions of the engineering evaluation of the coating system.

NextEra Energy Seabrook Response:

In SBK-L-11003 dated January 13, 2011(Reference 5), response to RAI B.2.1.22-3 Seabrook Station made reference to three different types of pipe coatings inside the Service Water Inspection Vault without adequate explanation of these products. An explanation of the types of coating products installed on the piping in the vault and a description of the physical piping and coating configuration is provided below.

Coating Systems Utilized in the Service Water Inspection Vault

Existing Coal-tar Coating System

This is the original vendor applied coal tar coating that was applied to the buried steel and stainless steel piping. This original vendor applied coal tar coating was fabricated and applied in accordance with the requirements of American Water Works Association (AWWA) Standard C203. This standard also meets the requirements of NACE SP0169-2007, "Standard Practice, Control of External Corrosion on Underground or Submerged Metallic Piping Systems", Table 1.

Tapecoat 20

Tapecoat 20 is a field applied coating system (i.e. for making repairs to the original vendor applied coal tar coating or coating the pipe at field welded joints). Tapecoat 20 is a 58 mil thick, hot applied coal tar coating (in tape form) that meets the original Seabrook Station pipe coating specification as well as the requirements of AWWAC203. See attached Tapecoat Company product sheet.

Keeler and Long 1000 Kolormastic

Keeler and Long 1000 Kolormastic is an epoxy based painting system. It utilizes a high solids combination of aluminum and stainless steel pigments dispersed in a two component polyamine epoxy to produce a coating that is chemically resistant. The dry film thickness of one coat of Keeler and Long 1000 Kolormastic is approximately 5-8 mils. See attached KL1000 product sheet.

Physical description of the vault piping and coating configuration

To provide access to the service water piping for periodic visual internal inspections, a portion of the underground piping was replaced with a removable spool piece. The modification to create the removable spool piece included excavating the pipe, pouring a concrete vault for future access to the spool pieces, cutting the pipe and installing flanges to the existing pipe and the new spool pieces.

The remaining original piping in the vault is coated with the original coal tar epoxy.

The installation of Tapecoat 20 was limited to the restoration of the original vendor applied coal tar coating on the existing pipe ends to which the mating sides of the drop-out spool flanges were welded.

The coating of the drop-out spools, including the flanges, consists of two coats of Keeler and Long 1000 Kolormastic epoxy-based paint with no additional over coating or wrapping. As stated above, the dry film thickness of each coat of Keeler and Long 1000 Kolormastic is approximately 5-8 mils.

Vendor Technical Data/Engineering Evaluation

Technical data from the vendor demonstrating that the Keeler and Long 1000 Kolormastic coating system is acceptable for long term immersion is not readily available. As stated in response to RAI B.2.1.22-3, the engineering change document that installed the drop-out spool pieces in the vaults stated that the painting system chosen for the service water piping within the vault was designed to protect the pipe from long term external corrosion based on continuous immersion in brackish, stagnant water. However, no separate engineering evaluation was performed for the specific products utilized for this application.

Method of Inspection/Acceptance Criteria

Seabrook Station has determined that periodic inspection of the vault piping is the best approach for managing the aging for these components.

Because the coating on the pipe spools consists only of two layers of paint, visual inspection of the pipe spools in the Service Water Inspection Vault, as prescribed by the Seabrook Station Buried Piping and Tanks Inspection Program (two inspections every ten years) will provide adequate indication of loss of material due to corrosion. Loss of coating integrity due to blistering, cracking, flaking, peeling, rusting, or physical damage would be readily apparent.

The coating applied to the flange-to-pipe weld and exposed piping outside of the spool piece (Tapecoat 20) meets the original pipe coating specification and AWWA Standard C203. This coating is a hot applied coal tar coating completely saturated into and bonded to both sides of a high tensile strength fabric. In addition, it has a polyester film adhering to the coating which facilitates unwinding of the roll and acts as an outer wrap. As described in the response to RAI B.2.1.22-3, water absorption of coal-tar enamels is extremely low making this the optimum choice of coatings. This portion of the piping in the Service Water vault will be visually inspected for damage or degradation of the coating.

Per the Seabrook Station Buried Piping and Tanks Inspection program, coated piping will be inspected and evaluated by an individual possessing a NACE operator qualification or by an individual otherwise meeting the qualifications to evaluate coatings as contained in 49 CFR 192 and 195. Any coating and wrapping degradation will be documented and evaluated under the corrective action program.

Plant Specific Operating Experience

Installation of the Service Water Inspection Vault drop-out spools was performed in 1995. Since that time, this vault has been accessed several times to remove one or more of the pipe spools for internal inspection of the Service Water buried piping. There has been no documented degradation to the paint on the pipe spools or the coal tar epoxy coating on the original pipe ends noted during these inspections.

Based on the above discussion, in Section B.2.1.22, as submitted in License Renewal Supplement 1 dated October 29, 2010 (SBK-L-10179), on Enclosure 1, page 13, the 1st paragraph of Element 6 - Acceptance Criteria is revised as follows:

For coated piping, there should be either no evidence of coating degradation or the type and extent of coating degradation should be insignificant as evaluated by an individual possessing a NACE operator qualification or by an individual otherwise meeting the qualifications to evaluate coatings as contained in 49 CFR 192 and 195. Any coating and wrapping degradation will be documented and evaluated under the corrective action program. ***Where the protective coating consists of paint with no other coating or wrapping (e.g., drop-out spools in the Service Water Inspection Vault), inspection of the painted surface should confirm no evidence of coating degradation (exposed metal) or degradation of the pipe surface due to corrosion.***

Tapecoat 20® Corrosion Protection

Features/Specifications/Application

Composition:

Tapecoat 20 consists of a specially formulated pliable coal tar coating completely saturated into and bonded to both sides of a high tensile strength fabric. In addition it has a polyester film adhering to the coating which facilitates unwinding of the roll and acts as an outerwrap, providing additional mechanical strength against backfill and soil stress.

Technical Data:

Softening Point: 170°F +/- 5°F
(77°C -3°C)

Penetration at 77°F: (25°C):11.81-31.49 mils.(3-.8 mm)

Thickness: 58 mils. +/- 2
(1.47 +/- .05 mm)

ASTM G-8 C.D.: Excellent

Oil & Hydrocarbon Resistance: Excellent
Meets Federal Spec HHT 30a

Meets AWWA Standard C203

Compatible with coal tar, asphalt, polyethylene, polypropylene, FBE and other factory coatings.

Tests Used: ASTM E-28; ASTM D-5; ASTM G-8; ASTM G-20. Tests are conducted according to the latest revisions.

Application

Equipment: A torch with wide mouth burner is recommended.

Surface Preparation: Surface must be clean and dry. Wire brush to remove any loose rust and scale, dust or dirt. Oil, grease and all other residue are to be removed from pipe surface. Use torch to warm the surface and remove moisture prior to priming.

Primer Application: TC Omni-prime is the compatible primer for use with Tapecoat 20. Apply primer to the prepared surface by brush or roller at the rate of approximately 250 square feet per gallon(7.37 m^2/liter). TC Omniprime should be applied 4" beyond the area to be wrapped with tape. Let primer dry before applying Tapecoat 20. TC Omniprime can also be used on stainless steel.

Tape Application: There are two recommended methods for applying Tapecoat 20 to a properly prepared and primed surface.

- **Spiral Wrap:** Flash flame of torch onto the side of the coating without the polyester film (outside of roll) until a smooth and glossy finish is obtained. Apply properly heated coating with tension to the surface of the pipe. Alternately heat and spiral wrap in a single thickness with a continuous 1/4" to 1" overlap (6.35 to 25.4 mm) of tape.
- **Cigarette Wrap:** Precut strips of Tapecoat 20 to a length equal to the circumference of the pipe plus a minimum of 3" for overlap. Follow general tape application instructions described above.

E.100

KEELER & LONG INC.

HEADQUARTERS:
P. O. Box 460
856 Echo Lake Road
Watertown, CT 06795
Tel (203) 274-6701
Fax (203) 274-5857

KOLORMASTIC
No. 1000 SERIES

GENERIC TYPE: POLYAMINE EPOXY WITH METALLIC PIGMENTS

PRODUCT DESCRIPTION: A high solids combination of aluminum and stainless steel pigments dispersed in a two component polyamine epoxy to produce a coating that is chemically resistant to splash or spillage of alkalies, acids, fresh and salt water, and most solvents.

RECOMMENDED USES: May be used to touch up inorganic or organic zinc rich primed surfaces which have been hand or power tool cleaned only. May be used for the painting or repainting of most steel surfaces, such as structural steel, tanks, bridges and piping.

NOT RECOMMENDED FOR: *Immersion service in strong acids or alkalies.*

COMPATIBLE TOPCOATS:

Kolor-Poxy Hi-Build Enamels

Kolor-Poxy Enamels	Anodic Self-Priming Paints
Kolorane Enamels	Poly-Silicone Enamels
Acrythane Enamels	Acite Hi-Build Enamels

PRODUCT CHARACTERISTICS:

Solids by Volume:	87% ± 3%
Solids by Weight:	92% ± 3%
Recommended Dry Film Thickness:	5.0 - 8.0 mils
Theoretical Coverage:	279 Sq. Ft./Gallon @ 5.0 mils DFT
Finish:	Metallic Luster, Satin Finish
Available Colors:	Aluminum and Limited Colors
Drying Time @ 72°F	
To Touch:	4 Hours
To Handle:	8 Hours
To Recoat:	24 Hours
VOC Content:	0.8 Pounds/Gallon 99 Grams/Liter

May, 1992

TECHNICAL BULLETIN

No. 1000 SERIES

E.100

TECHNICAL DATA

PHYSICAL DATA:	Weight per gallon:	10.6 ± 0.5 (pounds)
	Flash Point (Pensky-Martens):	>100°F
	Shelf Life:	2 Years
	Pot Life @ 72°F:	2 Hours
	Temperature Resistance:	200°F
	Viscosity @ 77°F:	Semi-Paste
	Gloss (60° meter):	25 ± 5
	Storage Temperature:	50 - 85°F
	Mixing Ratio (Approx. by Volume):	3:1
APPLICATION DATA:	Application Procedure Guide:	APG-8
	Wet Film Thickness Range:	5.7 - 9.2 mils
	Dry Film Thickness Range:	5.0 - 8.0 mils
	Temperature Range:	50 - 95°F (see APG-8)
	Relative Humidity:	80% Maximum
	Substrate Temperature:	Dew Point + 5°F
	Minimum Surface Preparation:	SSPC-SP2,SP3,SP6,SP7
	Induction Time @ 72°F:	None
	Recommended Solvent	
	@ 50 - 85°F:	No. 3700
	@ 86 - 95°F:	No. 2200

Application Methods

Air Spray	
Tip Size:	.073" - .086"
Pressure:	30 - 60 PSIG
Thin:	1.0 Qt/Gal (Maximum)
Airless Spray	
Tip Size:	.021" - .031"
Pressure:	2500 - 4000 PSIG
Thin:	1.0 Qt/Gal (Maximum)
Brush or Roller	
Thin:	1.0 Qt/Gal (Maximum)

KEELER & LONG INC.
P. O. Box 460, 856 Echo Lake Road
Watertown, CT 06795
Tel: (203) 274-6701 Fax: (203) 274-5857

KOLORS

SSPC STEEL STRUCTURES PAINTING COUNCIL
SUSTAINING MEMBER

E.100

Product Data Sheet

Keeler & Long

PPG High Performance Coatings

Keeler & Long/PPG
856 Echo Lake Road
Watertown, CT 06795
1-800-238-8596

Kolormastic™ KL1000/KL1000B Aluminum

Product Information

Product Code:	KL1000 Aluminum Part A KL1000B Curing Agent Part B
Product:	Epoxy-Polyamine
Suggested Use:	A primer/finish recommended for the paint or repaint of most steel surfaces such as structural steel, tanks, bridges and piping.
Not Recommended:	Immersion service in strong acids or alkalies.

Product Description

Color:	Aluminum
Gloss 60°:	20-40 typically
Weight/Gallon:	10.3 ± 0.5 lbs./gal. (mixed)
In Service Heat Limitations:	200°F (93°C) maximum, dry heat
Flash Point:	Part A 130°F (54.4°C) Part B 200°F (93.3°C)
Package:	KL1000 is filled in five gallon pails at 3.0 gallons (11.4 liters) or one gallon containers at 0.75 gallon (2.84 liters). KL1000B is filled in one gallon containers at 1.00 gallon (3.79 liters) or quart containers at 0.25 gallon (0.946 liters).
Percent Solids by Volume:	84.1 ± 3.0% (mixed, calculated)
Percent Solids by Weight:	88.7 ± 3.0% (mixed, applied and air dried)
VOC, Air Dried:	139 g/L (1.16 lbs./gal.) mixed
VOC, EPA 24:	164 g/L (1.37 lbs./gal.) mixed

Drying Schedule

Air Dry @ 77°F (25°C) ASTM D5895

Dry to Touch:	4 hours
Dry to Handle:	8 hours
Dry to Recoat:	24 hours
	Drying times listed may vary depending on temperature, humidity and air movement.

Application Data

Substrate:	Steel
Substrate Preparation:	The service life of the coating is directly related to the surface preparation. Remove all loose paint, mill scale and rust. The surface to be coated must be dimensionally stable, dry, clean and free of contamination. Steel Non-Immersion: SSPC-SP2/3 Hand/Power Tool Cleaning minimum. Immersion: SSPC-SP10 (NACE No. 2) Near White Metal Blast Cleaning minimum.
Topcoats:	Kolor-Poxy™ Hi-Build Enamels, Kolor-Poxy™ Enamels, Acrythane™ Enamels, Kolorane™ Enamels, Poly-Sil™ Enamels and Anodic Self-Priming Paints
Application Method:	Air Spray: DeVilbiss MBC gun, 704 or 765 air cap with "E" or "EX" tip and needle or equivalent equipment. Atomization Pressure: 30-60 psi. Airless Spray: Equipment capable of maintaining a minimum of 2500 psi at the tip without surge. 0.021" (0.533 mm) to 0.031" (0.787 mm) orifice. Brush: Use a high quality natural bristle brush. Roller: Use a 3/8" nap polyester-nylon roller cover with a solvent resistant core. Refer to Application Guide APG-8 for additional information.
Parts Base by Volume:	3 parts KL1000
Parts Catalyst by Volume:	1 part KL1000B
Thinner Code & Percent:	Thin up to 25% by volume with KL3700 as needed for application.
Digestion Time:	None required

E.100

Product Data Sheet

Keeler & Long

PPG High Performance Coatings

Keeler & Long/PPG
856 Echo Lake Road
Watertown, CT 06795
1-800-238-8596

Kolormastic™ KL1000/KL1000B Aluminum

Application Data (continued)

Pot Life:	4 hours at 77°F (25°C)
Coverage Sq. Ft/Gal. @ 1 mil:	1349 sq. ft./gal.
Mixing Instructions:	Mechanically agitate KL1000 Part A thoroughly. Add KL1000B Part B to KL1000 Part A. Mix thoroughly until uniform.
Wet Film Per Coat:	6.0 to 14.3 mils
Dry Film Per Coat:	5.0 to 12.0 mils
Clean Up Solvent:	KL3700

Additional Information

Apply only when air, product and surface temperatures are at least 50°F (10°C) and surface temperature is at least 5°F (3°C) above the dew point.

Store materials at temperatures between 50°F (10°C) and 85°F (29.4°C).

Permissible substrate temperature during application is 50°F (10°C) and 120°F (49°C).

Read all label and Material Safety Data Sheet (MSDS) information prior to use. MSDS are available by calling 1-800-238-8596.

Not intended for residential use.

Spray equipment must be handled with due care and in accordance with manufacturer's recommendation.

High-pressure injection of coatings into the skin by airless equipment may cause serious injury, requiring immediate medical attention at a hospital.

WARNING! If you scrape, sand, or remove old paint, you may release lead dust or fumes. LEAD IS TOXIC. EXPOSURE TO LEAD DUST OR FUMES CAN CAUSE SERIOUS ILLNESS, SUCH AS BRAIN DAMAGE, ESPECIALLY IN CHILDREN. PREGNANT WOMEN SHOULD ALSO AVOID EXPOSURE. Wear a properly fitted NIOSH-approved respirator and prevent skin contact to control lead exposure. Clean up carefully with a HEPA vacuum and a wet mop. Before you start, find out how to protect yourself and your family by contacting the USEPA National Lead Information Hotline at 1-800-424-LEAD or log on to www.epa.gov/lead. In Canada contact a regional Health Canada office. Follow these instructions to control exposure to other hazardous substances that may be released during surface preparation.

Request for Additional Information (RAI) B.2.1.22-5

Background:

In LRA Supplement 2 dated November 15, 2010, the applicant revised LRA Table 3.3.2-37 to include copper-alloy (with> 15% zinc) valves and bolting exposed to raw water in the submerged underground vault for service water piping. The applicant stated that the components will be managed for aging by the Buried Piping and Tanks Inspection Program.

Issue:

The applicant did not revise LRA Section B.2.1.22 to reflect inclusion of this material nor to provide inspection frequencies.

Request:

Revise LRA Section B.2.1.22 to reflect inclusion of copper-alloy (>15% zinc) and state the number of planned inspections of these components.

NextEra Energy Seabrook Response:

In Section B.2.1.22, as submitted in Supplement 1 dated October 29, 2010 (SBK-L-10179), in Enclosure 1, on page 13 of 18, the Inaccessible Submerged Piping Inspection Locations table is revised as follows:

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

GENERAL NOTES:

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

Enclosure 3 to SBK-L-11062

LRA Appendix A - Final Safety Report Supplement

Table A.3 License Renewal Commitment List

A.3 LICENSE RENEWAL COMMITMENT LIST

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
1.	PWR Vessel Internals	An inspection plan for Reactor Vessel Internals will be submitted for NRC review and approval at least twenty-four months prior to entering the period of extended operation.	A.2.1.7	Program to be implemented prior to the period of extended operation. Inspection plan to be submitted to NRC not less than 24 months prior to the period of extended operation.
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

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
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 guidance for "where sprinklers have been in place for 50 years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory for field service testing".	A.2.1.16	Prior to the period of extended operation.
10.	Fire Water System	Enhance the program to include the performance of periodic flow testing of the fire water system in accordance with the guidance of NFPA 25.	A.2.1.16	Prior to the period of extended operation.

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
11.	Fire Water System	Enhance the program to include the performance of periodic visual or volumetric inspection of the internal surface of the fire protection system upon each entry to the system for routine or corrective maintenance. These inspections will be documented and trended to determine if a representative number of inspections have been performed prior to the period of extended operation. If a representative number of inspections have not been performed prior to the period of extended operation, focused inspections will be conducted. These inspections will be performed within ten years prior to the period of extended operation.	A.2.1.16	Within ten years prior to the period of extended operation.
12.	Aboveground Steel Tanks	Enhance the program to include components and aging effects required by the Aboveground Steel Tanks.	A.2.1.17	Prior to the period of extended operation.
13.	Aboveground Steel Tanks	Enhance the program to include an ultrasonic inspection and evaluation of the internal bottom surface of the two Fire Protection Water Storage Tanks.	A.2.1.17	Within ten years prior to the period of extended operation.
14.	Fuel Oil Chemistry	Enhance program to add requirements to 1) sample and analyze new fuel deliveries for biodiesel prior to offloading to the Auxiliary Boiler fuel oil storage tank and 2) periodically sample stored fuel in the Auxiliary Boiler fuel oil storage tank.	A.2.1.18	Prior to the period of extended operation.
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.

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
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.

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
21.	Reactor Vessel Surveillance	Enhance the program to ensure that any capsule removed, without the intent to test it, is stored in a manner which maintains it in a condition which would permit its future use, including during the period of extended operation.	A.2.1.19	Prior to the period of extended operation.
22.	One-Time Inspection	Implement the One Time Inspection Program.	A.2.1.20	Within ten years prior to the period of extended operation.
23.	Selective Leaching of Materials	Implement the Selective Leaching of Materials Program. The program will include a one-time inspection of selected components where selective leaching has not been identified and periodic inspections of selected components where selective leaching has been identified.	A.2.1.21	Within five years prior to the period of extended operation.
24.	Buried Piping And Tanks Inspection	Implement the Buried Piping And Tanks Inspection Program.	A.2.1.22	Within ten years prior to entering the period of extended operation
25.	One-Time Inspection of ASME Code Class 1 Small Bore-Piping	Implement the One-Time Inspection of ASME Code Class 1 Small Bore-Piping Program.	A.2.1.23	Within ten years prior to the period of extended operation.
26.	External Surfaces Monitoring	Enhance the program to specifically address the scope of the program, relevant degradation mechanisms and effects of interest, the refueling outage inspection frequency, the inspections of opportunity for possible corrosion under insulation, the training requirements for inspectors and the required periodic reviews to determine program effectiveness.	A.2.1.24	Prior to the period of extended operation.

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

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

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
42.	Metal Fatigue of Reactor Coolant Pressure Boundary	Enhance the program to implement a software program, to count transients to monitor cumulative usage on selected components.	A.2.3.1	Prior to the period of extended operation.
43.	Pressure –Temperature Limits, including Low Temperature Overpressure Protection Limits	Seabrook Station will submit updates to the P-T curves and LTOP limits to the NRC at the appropriate time to comply with 10 CFR 50 Appendix G.	A.2.4.1.4	The updated analyses will be submitted at the appropriate time to comply with 10 CFR 50 Appendix G, Fracture Toughness Requirements.
44.	Environmentally-Assisted Fatigue Analyses (TLAA)	NextEra Seabrook will perform a review of design basis ASME Class 1 component fatigue evaluations to determine whether the NUREG/CR-6260-based components that have been evaluated for the effects of the reactor coolant environment on fatigue usage are the limiting components for the Seabrook plant configuration. If more limiting components are identified, the most limiting component will be evaluated for the effects of the reactor coolant environment on fatigue usage. If the limiting location identified consists of nickel alloy, the environmentally-assisted fatigue calculation for nickel alloy will be performed using the rules of NUREG/CR-6909. (1) Consistent with the Metal Fatigue of Reactor Coolant Pressure Boundary Program Seabrook Station will update the fatigue usage calculations using refined fatigue analyses, if necessary, to determine acceptable CUFs (i.e., less than 1.0) when accounting for the effects of the reactor water environment. This includes applying the appropriate F_{en} factors to valid CUFs determined from an existing fatigue analysis valid for the period of extended operation or from an analysis using an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case).	A.2.4.2.3	At least two years prior to entering the period of extended operation.

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
		(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).		
45.	Mechanical Equipment Qualification	Revise Mechanical Equipment Qualification Files.	A.2.4.5.9	Prior to the period of extended operation.
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

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
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 testing of the containment liner plate for loss of material.	A.2.1.17	Prior to the period of extended operation.
51.	ASME Section XI, Subsection IWL	Perform confirmatory testing and evaluation of the Containment Structure concrete	A.2.1.28	Prior to the period of extended operation
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	Prior to the period of extended operation
53.	Reactor Head Closure Studs	Replace the spare reactor head closure stud(s) manufactured from the bar that has a yield strength > 150 ksi with ones that do not exceed 150 ksi.	A.2.1.3	Prior to the period of extended operation.
54.	Steam Generator Tube Integrity	Unless an alternate repair criteria changing the ASME code boundary is permanently approved by the NRC, or the Seabrook Station steam generators are changed to eliminate PWSCC-susceptible tube-to-tubesheet welds, submit a plant-specific aging management program to manage the potential aging effect of cracking due to PWSCC at least twenty-four months prior to entering the Period of Extended Operation.	A.2.1.10	Program to be submitted to NRC at least 24 months prior to the period of extended operation.

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
55.	Steam Generator Tube Integrity	Seabrook will perform an inspection of each steam generator to assess the condition of the divider plate assembly.	A.2.1.10	Prior to entering the period of extended operation
56.	Closed-Cycle Cooling Water System	Revise the station program documents to reflect the EPRI Guideline operating ranges and Action Level values for hydrazine and sulfates.	A.2.1.12	Prior to entering the period of extended operation.
57.	Closed-Cycle Cooling Water System	Revise the station program documents to reflect the EPRI Guideline operating ranges and Action Level values for Diesel Generator Cooling Water Jacket pH.	A.2.1.12	Prior to entering the period of extended operation.
58.	Fuel Oil Chemistry	Update Technical Requirement Program 5.1, (Diesel Fuel Oil Testing Program) ASTM standards to ASTM D2709-96 and ASTM D4057-95 required by the GALL XI.M30 Rev 1	A.2.1.18	Prior to the period of extended operation.
59.	Nickel Alloy Nozzles and Penetrations	The Nickel Alloy Aging Nozzles and Penetrations program will implement applicable Bulletins, Generic Letters, and staff accepted industry guidelines.	A.2.2.3	Prior to the period of extended operation.
60.	Buried Piping and Tanks Inspection	Implement the design change replacing the buried Auxiliary Boiler supply piping with a pipe-within-pipe configuration with leak indication capability.	A.2.1.22	Prior to entering the period of extended operation.
61.	Compressed Air Monitoring Program	Replace the flexible hoses associated with the Diesel Generator air compressors on a frequency of every 10 years.	A.2.1.14	Within ten years prior to entering the period of extended operation.
62.	Water Chemistry	Enhance the program to include a statement that sampling frequencies are increased when chemistry action levels are exceeded.	A.2.1.2	Prior to entering the period of extended operation.

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
63.	*Flow Induced Erosion*	*Ensure that the quarterly CVCS Charging Pump testing is continued during the PEO. Additionally, add a precaution to the test procedure to state that an increase in the CVCS Charging Pump mini flow above the acceptance criteria may be indicative of erosion of the mini flow orifice as described in LER 50-275/94-023.*	*N/A*	*Prior to the period of extended operation*
64.	*Buried Piping and Tanks Inspection*	*Soil analysis shall be performed prior to entering the period of extended operation to determine the corrosivity of the soil in the vicinity of non-cathodically protected steel pipe within the scope of this program. If the initial analysis shows the soil to be non-corrosive, this analysis will be re-performed every ten years thereafter.*	*A.2.1.22*	*Prior to entering the period of extended operation.*