UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

January 14, 2013

Mr. Kevin Walsh, Site Vice President
c/o Michael O'Keefe
Seabrook Station
NextEra Energy Seabrook, LLC
P.O. Box 300
Seabrook, NH 03874

SUBJECT: SEABROOK STATION, UNIT 1 - REQUEST FOR RELIEF TO USE AN ALTERNATIVE TO THE REQUIREMENTS OF THE AMERICAN SOCIETY OF MECHANICAL ENGINEERS BOILER AND PRESSURE VESSEL CODE, SECTION XI (TAC NO. ME9187)

Dear Mr. Walsh:

By letters dated August 1, 2012 (Agencywide Documents Access and Management System (ADAMS) Accession Number ML12219A129) with supplemental letters dated September 7, 2012 (ADAMS Accession Number ML12265A119), September 25, 2012 (ADAMS Accession Number ML12270A369), and December 13, 2012 (ADAMS Accession Number ML12354A204), NextEra Energy Seabrook, LLC (NextEra or licensee) requested relief from the requirements of the American Society of Mechanical Engineers *Boiler and Pressure Vessel Code* (ASME Code), Section XI, Subarticle IWA-4422.1.

Specifically, pursuant to Title 10 of the *Code of Federal Regulations* (10 CFR) 50.55a(a)(3)(ii), the licensee requested to use the alternative in Relief Request RA-12-001 on the basis that complying with the specified ASME Code requirement would result in hardship or unusual difficulty. Relief Request RA-12-001 is applicable to the alternative repair of the buried service water (SW) pipes. Revision 0 of the relief request was submitted in a letter dated August 1, 2012. As a result of the U.S. Nuclear Regulatory Commission (NRC) staff's requests for additional information, the licensee submitted Revisions 1 and 2 of the relief request in letters dated September 7, 2012, and December 13, 2012, respectively.

The licensee is scheduled to examine the buried SW piping in accordance with the requirements of the Seabrook buried piping program during the next refueling outage. Should repair be needed as a result of the inspection findings, the licensee requested relief from the ASME Code, Section XI, Subarticle IWA-4422.1 requirements that defective portions of components be removed prior to performing a repair activity by welding. Seabrook is in the third 10-year inservice inspection interval which ends on August 18, 2020.

All other requirements of ASME Code, Section XI for which relief has not been specifically requested remain applicable, including third-party review by the Authorized Nuclear Inservice Inspector.

If you have any questions, please contact John G. Lamb at 301-415-3100 or via e-mail at John.Lamb@nrc.gov.

Sincerely,

John D. Hughey FOR

Meena Khanna, Chief
Plant Licensing Branch I-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-443

Enclosure:
Safety Evaluation

cc w/encl: Distribution via Listserv

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

REQUEST FOR RELIEF - REPAIR OF BURIED SERVICE WATER PIPING

NEXTERA ENERGY SEABROOK, LLC

SEABROOK STATION, UNIT 1

DOCKET NO. 50-443

1.0 INTRODUCTION

By letters dated August 1, 2012 (Agencywide Documents Access and Management System (ADAMS) Accession Number ML12219A129) with supplemental letters dated September 7, 2012 (ADAMS Accession Number ML12265A119), September 25, 2012 (ADAMS Accession Number ML12270A369), and December 13, 2012 (ADAMS Accession Number ML12354A204), NextEra Energy Seabrook, LLC (NextEra or licensee) requested relief from the requirements of American Society of Mechanical Engineers *Boiler and Pressure Vessel Code* (ASME Code), Section XI, subarticle IWA-4422.1.

Specifically, pursuant to Title 10 of the *Code of Federal Regulations* (10 CFR) 50.55a(a)(3)(ii), the licensee requested to use the alternative in Relief Request RA-12-001 on the basis that complying with the specified ASME Code requirement would result in hardship or unusual difficulty. Relief Request RA-12-001 is applicable to the alternative repair of the buried service water (SW) pipes. Revision 0 of the relief request was submitted in the letter dated August 1, 2012. As a result of the U.S. Nuclear Regulatory Commission (NRC) staff's requests for additional information, the licensee submitted Revisions 1 and 2 of the relief request in letters dated September 7, 2012, and December 13, 2012, respectively.

The licensee is scheduled to examine the buried SW piping in accordance with the requirements of the Seabrook buried piping program during the next refueling outage. Should repair be needed as a result of the inspection findings, the licensee requested relief from the ASME Code, Section XI, subarticle IWA-4422.1 requirements that defective portions of components be removed prior to performing a repair activity by welding. Seabrook is in the third 10-year inservice inspection (ISI) interval which ends on August 18, 2020.

2.0 REGULATORY EVALUATION

Pursuant to 10 CFR 50.55a(g)(4), ASME Code Class 1, 2, and 3 components (including supports) will meet the requirements, except the design and access provisions and the preservice examination requirements, set forth in the ASME Code, Section XI, "Rules for Inservice Inspection (ISI) of Nuclear Power Plant Components," to the extent practical within the limitations of design, geometry, and materials of construction of the components. The

Enclosure

regulations require that inservice examination of components and system pressure tests conducted during the first 10-year ISI interval and subsequent intervals comply with the requirements in the latest edition and addenda of Section XI of the ASME Code incorporated by reference in 10 CFR 50.55a(b) 12 months prior to the start of the 120-month interval, subject to the limitations and modifications listed therein.

Pursuant to 10 CFR 50.55a(a)(3), alternatives to the ASME Code requirements may be authorized by the NRC if the licensee demonstrates that: (i) the proposed alternative provides an acceptable level of quality and safety, or (ii) compliance with the specified requirements would result in hardship or unusual difficulty without a compensating increase in the level of quality and safety.

Based on the above, and subject to the following technical evaluation, the NRC staff finds that regulatory authority exists for the licensee to request the use of an alternative and the NRC to authorize the alternative proposed by the licensee.

3.0 TECHNICAL EVALUATION

3.1 Relief Request RA-12-001, Revision 2

3.1.1 ASME Code Component Affected

Revision 0 of the relief request includes the "A" train 24-inch diameter SW supply pipes, line numbers 1801-3 and 1818-3, which supply cooling water to the Primary Component Cooling Water (PCCW) Heat Exchanger CC-E-17-A. These lines supply and return seawater to and from the PCCW Heat Exchanger, which is used to remove heat from systems and components during normal plant operation and emergency plant evolutions.

Revision 1 of the relief request includes the "A" train 24-inch diameter SW pipe, line number SW-1810-003 as an affected component in addition to line numbers 1801-003 and 1818-003.

In the letter dated December 13, 2012, the licensee incorporated into Relief Request RA-12-001, Revision 2, "B" train 24-inch SW piping, line numbers SW-1082-003-153-24", SW-1820-003-153-24", and SW-1812-003-153-24".

3.1.2 Applicable Code Edition and Addenda

The applicable Code of Record for the current 10-Year ISI program is the ASME Code, Section XI, 2004 Edition with no Addenda. The affected portion of the service water piping was designed and constructed in accordance with the requirements of the ASME Code, Section III, Subsection ND, 1977 Edition, with no Addenda.

3.1.3 Applicable Code Requirement

ASME Code, Section XI, IWA-4422.1 requires that defects be removed or reduced to an acceptable size prior to implementing a repair or replacement in accordance with the requirements of IWA-4000. The proposed repair method would not be consistent with IWA-4422.1 and, thus, the relief is requested.

3.1.4 Reason for Request

During the scheduled fall 2012 refueling outage, the licensee entered the "A" train SW buried piping to inspect the cement lining. The licensee was concerned it may find a localized area of liner loss and need to repair the liner and potentially the pipe. The licensee stated that it would be challenging to repair the degraded pipe in accordance with ASME Section XI, Article IWA-4000 due to the confined space of the piping inside diameter (ID) of 22.50 inches (24-inch nominal pipe, standard schedule, 0.375-inch liner), which presents a significant personnel safety concern. Some portions of the buried SW piping are located 24.50 feet below grade, with pipe run lengths several hundred feet from the point of entry. Full defect removal of discovered thin wall sections may result in a through wall defect. This case, and in those situations where a through wall defect is discovered, would result in the potential for in-leakage of groundwater into the pipe along with possible exposure to asbestos used in the external pipe wrap.

3.1.5 Proposed Alternative and Basis for Use

In lieu of the requirements of the ASME Code, Section XI, IWA-4422.1 discussed above, the licensee will not remove the degraded area prior to implementing an IWA-4000 repair (i.e., the Code repair). Instead, the licensee will clean the corroded areas and assess visually for signs of other damage mechanisms, specifically the presence of cracking. If the degraded area appears consistent with no cracking present, the licensee proposed to repair the degraded area by the application of an encapsulation device in accordance with the provisions of IWA-4000.

The proposed structural repair consists of welding a circular encapsulation device to the inside surface of the pipe. The device is designed to accommodate the design pressure and mechanical loading. Since welding of the circular cap inside the pipe wall will impact the capability of the exterior wrap to preclude outer diameter (OD) corrosion due to contact with ground water, no credit will be taken for the localized external wrap in determining the service life of the repair. The licensee stated that the encapsulation cap ID (the diameter of the device) will be greater than the maximum diameter of the defective area plus a minimum of twice the nominal thickness of the pipe. The NRC staff noted that Revision 0 of the relief request specified the 6-inch diameter encapsulation device. However, by letter dated September 25, 2012, the licensee added a 4-inch encapsulation device in addition to the 6-inch device as a repair option.

The pipe material is concrete lined standard wall, carbon steel, SA-106, Grade B. The proposed encapsulation device material is SA-105 or SA-350 Grade LF2, while the welding process to be used in the repair is metal inert gas with an ER 70S-6 weld wire. The licensee will perform welding per the requirements of the ASME Code, Section XI, using qualified welders and the weld procedure will be qualified in accordance with the ASME Code, Section XI.

The proposed encapsulation device is a pipe restoration approach equivalent to an unstayed flat head. ASME Section III, Subsection ND, Figure ND-3325-1 depicts acceptable configurations for flat heads. The relevant configuration for the encapsulation device is shown in Figure B-2 of Figure ND-3325-1. The dimension of the cap top, skirt, and full penetration weld to the pipe are based upon the metal area replacement ASME Code methodology and considers design pressure, external soil pressure, as well as mechanical loading. The size of the cap considered the future metal loss due to both seawater (internal content) and groundwater (external environment) during the period of service.

Before installation, the licensee will clean the inside surface of the pipe and use a contour gauge to determine the extent of wall loss. Upon discovery of a degraded area with pipe wall thickness less than ASME Code required, the licensee will further clean the degraded area. The licensee will perform ultrasonic testing (UT) to establish that the existing surrounding area, consisting of good wall (sufficient wall thickness to support welding of the repair) is available. This UT examination will address the possible existence of external OD corrosion. After the encapsulation device is installed, the licensee will perform liquid penetrant (PT) or magnetic particle (MT) examination of the final attachment weld pass.

The licensee stated that upon return to operation, and in consideration that the pipe is buried, post repair monitoring is not possible. The repaired location will be placed into the Seabrook Buried Pipe Inspection Program. The licensee will excavate the piping in the future prior to the end of the 36-month service period for the purpose of defect removal from the exterior and repair of the external wrap.

Seabrook typically uses 30 mils per year (mpy) for a corrosion rate of carbon steel piping exposed to seawater. Based upon industry review, the licensee stated that it uses a corrosion rate of 10 mpy for the exterior of the carbon steel pipe subjected to groundwater. The licensee will use a total corrosion rate of 40 mpy for the corrosion in the inside surface of the pipe to ensure that the potential continued corrosion of the encapsulated pipe wall and the inner surface of the cap and its attachment welds remain intact during the intended service life of the repair.

The licensee stated that the encapsulation device will be designed to accommodate all appropriate deadweight, pressure, and seismic loads. The licensee further stated that because the service water system operates at a low temperature, differential thermal expansion between the encapsulation device and the repaired component is not a concern.

3.1.6 Duration of Proposed Alternative

The licensee stated that use of the relief request resulting in the installation of the internal encapsulation device will have a limited service life of two operating cycles (approximately 36 months). The licensee further stated that encapsulation of the degraded area shall be used only once at each identified location.

3.2 Staff Evaluation

3.2.1 Encapsulation Device Design

A diagram of the proposed encapsulation device is shown in Figure A of the relief request and identifies a center weld root standoff hub. In the letter dated September 7, 2012, the licensee explained that the purpose of the center weld root standoff hub was for positioning only, to assist the installer in attaining the weld root gap required to make a full penetration weld joining the skirt of the device to the pipe. The center weld root standoff hub was provided as an alignment aid in achieving the required 3/32 inch to 1/8 inch weld root gap at installation. If internal pipe contact surface irregularities interfere with a standoff hub such that the desired weld root gap cannot be achieved, the installer has the option of altering or removing the standoff hub.

Section 5 of the relief request states that the encapsulation cap ID will be such that the ID is greater than the maximum diameter of the defective area plus a minimum of twice the nominal thickness of the pipe. The NRC staff asked the licensee to explain how this sizing method will bound the potential corrosion growth in the lateral direction of the pipe for the design life of the encapsulation. In the letter dated September 7, 2012, the licensee clarified that using the corrosion rate of 40 mpy over the service life (36 months) of the encapsulation results in a projected future metal loss of 0.120 inches. The twice nominal thickness of the pipe (2 x 0.375 = 0.750 inches) more than accommodates the metal loss in the lateral direction. The licensee explained that the 40 mpy corrosion rate is based on 30 mpy from seawater corrosion of carbon steel plus the 10 mpy of soil/steel corrosion interaction. This corrosion rate is applied to the base metal depth and the lateral direction of the pipe wall. The licensee stated that historically, the only potential degradation mechanisms observed for carbon steel piping immersed in seawater is general corrosion in the form of general wasting or pitting. The licensee will weld an Inconel liner to the encapsulation device to minimize corrosion on the cap. In addition, the licensee will apply a coating, in the form of bonded epoxy such as, Belzona or Splashzone, to the inconel liner material and reapply concrete around the cap. The NRC staff notes that there may be adverse situations in which the corrosion rate may be higher than 40 mpy. However, the NRC staff notes that the surface of the encapsulation device will be covered with an Inconel liner and on top of that a coat of epoxy to minimize the corrosion from contacting with seawater; therefore, given the limited duration of the relief request, (i.e., 36 months) the use of 40 mpy corrosion growth rate is acceptable. The NRC staff finds that the device is sized to have sufficient margin to bound the potential metal loss in the lateral direction and, therefore, the device sizing is acceptable.

After installation, the device will protrude from the ID surface of the pipe and may act as an obstacle for fluid flow (i.e., as a flow restrictor). The NRC staff questioned whether there is a limit on the number of the encapsulations that can be installed so as not to restrict the fluid flow. In addition, the NRC staff questioned whether the fluid impinging on the side (the cross-sectional area) of the encapsulation will affect its structural integrity. In the letter dated September 7, 2012, the licensee stated that the maximum final thickness (height) of the 4-inch and 6-inch diameter encapsulation device are 0.975 inches and 1.074 inches, respectively. This is based on the thickness of the nominal cap, fabrication tolerance, Inconel 625 liner, root weld gap, and an air gap.

The licensee calculated flow impingement on the encapsulation device based on a velocity of 16 feet/second in the SW pipe. The flow impingement load is applied to the total encapsulation device height. The licensee tracks the impact on flow capability associated with internally installed components. The specific design change documentation will assess the encapsulation device installation impact and dictate the number of acceptable potential flow restrictions. The NRC staff finds that the licensee's flow impingement calculation has satisfactorily addressed the concerns because the calculation has shown that the design of the encapsulation and associated attachment weld will not be significantly affected by the impingement loads. The NRC staff finds it is acceptable that the licensee will track the flow condition in the pipe to limit the number of devices that can be installed.

The licensee's design analyses (proprietary) are presented in Attachment 2 to the letter dated September 7, 2012. The NRC staff finds that the licensee's stress analyses followed the design analysis requirements of the 2004 Edition of the ASME Code, Section III, ND-3100 and 3600. The material allowable stresses were taken from the ASME Code, Section II, 2004 Edition. The operating conditions of subject piping lines are 65 degrees F and 75 psi. The design conditions are 200 degrees F and 150 psi. The NRC staff finds that the design analysis of the encapsulation device satisfies all the relevant allowable stresses of the ASME Code, Section III.

3.2.2 Application

The NRC staff questioned the potential for weld shrinkage and high localized weld stresses in the pipe if two encapsulation devices are installed close to each other. In the letter dated September 7, 2012, the licensee explained that a distance of 5.262 inches will be imposed based on the mean pipe radius and the nominal pipe thickness. However, the licensee's calculation attached to the September 7, 2012, submittal specifies a distance of 6.12 inches between the two adjacent encapsulation devices. By letter dated September 25, 2012, the licensee clarified that the 6.120-inch distance was calculated based on the criteria of the ASME Code, Section III, ND-3643.3 criteria for "Special Requirements for Extruded Outlets." The 5.262-inch distance was calculated using criteria in the ASME Code, Section XI, Code Case N-661-1, "Alternative Requirements for Wall Thickness Restoration of Class 2 and 3 Carbon Steel Piping for Raw Water Service." The licensee stated that both methods are acceptable for calculating the minimum distance between two adjacent encapsulation devices. However, the licensee will use the conservative distance of 6.120 inches should the installation of an adjacent encapsulation device be required. The NRC staff finds the distance of 6.120 inches is appropriate because it requires a longer distance between two devices than 5.262 inches to minimize welding distortion.

The NRC staff asked the licensee to clarify whether in addition to the repair for wall thinning, the proposed design is also applicable to repair a 100-percent through-wall flaw. By letter dated September 7, 2012, the licensee explained that the proposed design is applicable to repair a 100-percent through-wall flaw. In the instances where a 100-percent through-wall leak is detected or results due to surface preparation, the through-wall hole will be appropriately plugged with a common type device (e.g., plug) to stop any flow and facilitate the enclosure application. The licensee noted that the device design has addressed the concern over internal corrosion of the enclosure by the consideration of the projected future metal loss anticipated to occur during the service life of two operating cycles. The NRC staff finds that the licensee has satisfactorily addressed the repair of the 100-percent through-wall flaw.

Section 6 of the relief request states that the encapsulation device will have a limited service life of two operating cycles (approximately 36 months). By letter dated September 7, 2012, the licensee explained that Seabrook has two redundant trains of the SW system. During the 2012 fall refueling outage, the "A" train of SW pipe was inspected, followed by the "B" train during the following outage. The 36-month service life duration is obtained by the total duration of the two full operating cycles (18-months each). Encapsulations installed in the fall 2012 refueling outage will be replaced in the subsequent outage in which the "A" train will be scheduled for maintenance (i.e., fall 2015). The licensee further clarified that the defective portion of piping will be entered into the Corrective Action Program and scheduled for repair within two operating cycles. The defect will be removed by an accepted ASME Code repair via the outside diameter of the pipe within the 36-month service period of the encapsulation device. The remaining material will be treated and coated with bonded epoxy, such as Belzona. The piping will be rewrapped. The NRC staff finds that the 36-month service life is acceptable for the subject temporary repair because the device is sized based on the corrosion growth for the 36-month duration.

3.2.3 Pre-Installation Inspection And Preparation

In the letter dated September 7, 2012, the licensee stated that prior to installing the encapsulation, it will inspect approximately 100 feet of pipe line SW-1801-003-153-24", approximately 190 feet of pipe line SW-1810-003-153-24" and approximately 200 feet of pipe line SW-1818-003-153-24." Upon discovery of a questionable liner location, (i.e. rust bloom, rust stain, cracked concrete) the licensee will clean the pipe/cement wall surface to be free of any debris, scale, rust, or other surface conditions that would interfere with the accurate profiling of the corroded pipe metal surface.

The locations where the cement liner appears damaged are where the SW piping will be cleaned of corrosion products and failed liner remnants and inspected. The licensee stated that it is not feasible to clean the liner for the entire length of the inspection scope. If the cement liner is damaged, but no degradation is present on the pipe wall inside diameter metal surface (no rust staining), no further inspection of the location is required. The licensee will restore the liner using Carboline Splash Zone A-788 or Belzona ceramic Rmetal. The material used to restore the liner will also be used to bond to the encapsulation device, steel pipe and the existing cement liner by adhesion, based on the inherent adhesional property of the material. The restored liner material has a negligible moisture vapor permeability property. Therefore, it will provide an effective corrosion barrier. The NRC staff finds that the licensee's preparation for installation is acceptable because the licensee will clean the surface of the liner and pipe prior to installation.

3.2.4 Characterization of Degradation

Once a degraded pipe area is identified, the licensee will use a chipping hammer or other suitable tool to verify the surface to be profiled is down to clean metal. The licensee will lightly tap the degraded area and the adjacent base material to ensure that the surface is metal and not a tightly adhering scale layer. Upon confirmation of base metal, the licensee will verify degradation as consistent with base material corrosion and that other types of potential degradation are not present (i.e. cracking or mechanical wear). The licensee will assess the degradation in accordance with the ASME Code, Section XI.

The licensee will profile the deepest part of the degraded area using a pin type contour gauge. Two subsequent profiles will be taken from the deepest area using the contour gauge to determine the greatest extent of degradation. Additionally, the surface profile will include 1.50 inches of clean, non-degraded base material (minimum) on both sides of the profile plot in order to establish a reference surface. The licensee will determine the maximum depth of the degraded area by measuring the distance from the reference surface to the deepest point along the contour plot. The maximum depth of the degraded area will be subtracted from the commercial minimum wall thickness (87.5% of nominal wall thickness), and this value will be reported as the remaining thickness of the pipe.

The licensee stated that if the remaining thickness of the pipe is greater than the calculated (acceptable) minimum thickness, no further inspection action is required. If the remaining thickness of the pipe is less than the calculated minimum thickness, the licensee will perform a UT measurement to determine the actual thickness of the pipe adjacent to the degraded area.

The NRC staff asked the licensee to explain why UT is not used to measure the thickness of both the cement liner and pipe wall in the beginning of the pre-installation inspection. By letter dated September 7, 2012, the licensee responded that a contour gauge is used initially in lieu of UT to determine pipe wall loss because of the infeasibility of using UT. The method by which the pipe will be cleaned does not result in a surface upon which an UT can be performed. The cleaning method does, however, ensure that the corrosion products are removed without further reduction of the base metal thickness. The resulting surface is non-uniform, preventing adequate UT transducer contact. Additional cleaning to a level where UT testing is possible would require more aggressive cleaning methods resulting in base metal removal. The licensee stated that this more aggressive cleaning would lead to a risk of reducing pipe wall thickness below the minimum structural thickness and/or the minimum thickness on which a base metal repair can be performed, in addition to the added risk of a through-wall leak developing.

To preclude these risks, the licensee elected to use the contour gauge to characterize the flaw. The existing surrounding wall will be location-specific and dependent upon the relationship between the extent of the pipe wall degradation and the proposed size of the repair encapsulation. By letter dated September 7, 2012, the licensee clarified that the minimum pipe wall thickness required for a repair to be performed is 0.120 inches. The licensee does not take credit for the cement liner for structural or pressure boundary integrity. The licensee stated that minimum wall thickness is based on the code allowable wall thickness as determined in accordance with the ASME Code, Section III, Subsection ND-3641, 1977 Edition.

The NRC staff asked the licensee to discuss how the degradation from the outside surface of the pipe will be determined, especially for those locations where the inside surface cement liner is not damaged. In the letter dated September 7, 2012, the licensee noted that it does not measure thickness of the concrete liner, since its intended function is to act as a protective coating. Concrete depth measurement is inconsequential; of concern is its ability to provide a protective coating. The buried service water system piping is both coal tar wrapped and has cathodic protection on its outside surface. Based upon this, the licensee stated that external pipe wall degradation is not suspected. The NRC staff notes that Seabrook station is participating in the industry's buried and underground piping and tanks inspection initiative (NEI 09-14). NRC Region I inspectors have recently reviewed the licensee's Buried Piping Integrity Program and found it to be consistent with initiative requirements. The NRC staff finds it is acceptable that the general corrosion initiated from the outside surface will be monitored by the Buried Pipe Integrity Program.

The NRC staff finds that the use of the contour gage, in lieu of UT, to characterize the non-planar flaw and measure the degraded area is acceptable for the general corrosion. The NRC staff notes that the contour gage cannot be used to characterize a flaw caused by stress-corrosion cracking. The NRC staff notes that based on operating experience it is unlikely that stress-corrosion cracking would occur in carbon steel which is used in the SW piping.

3.2.5 Welding Of Encapsulation Device

The licensee will clean the subject pipe to bright metal prior to welding the encapsulation onto the pipe inside surface and will include an area approximately 1 inch beyond the welded area for performance of final nondestructive examination (NDE). The fit-up gap shall be approximately 3/32 inches or as specified on design drawing. This is the dimension of the weld root opening or the gap between the encapsulation device and the pipe inside surface. The licensee will install a plug in a through-wall hole, if required, to alleviate root pass degradation due to air or water in-leakage. The licensee will use site welding procedures qualified for the open root configuration. Final NDE will be either PT or MT examination in accordance with the requirements for the ASME Class 3 piping systems. The licensee will review the physical installation to verify it is in compliance with all implementation procedures and applicable design documents. The NRC staff finds it acceptable that the licensee will follow the ASME Code requirements for NDE and qualified procedures for welding.

3.2.6 Acceptance Examination

As stated in the letter dated September 7, 2012, the acceptance criteria for indications identified in the PT or MT examination of the welds will be based on ASME Section III, Subsection ND. Indications whose major dimensions are greater than 1/16 inches shall be considered relevant. The licensee stated that the following relevant indications are unacceptable: (1) Any crack or linear indication, (2) Rounded indications with dimensions greater than 3/16 inches, (3) Four or more rounded indications in a line separated by 1/16 inches or less, edge to edge, and (4) Ten or more rounded indications in any 6-inch square of surface with the major dimension of this area not to exceed 6 inches with the area taken in the most unfavorable location relative to the indications being evaluated. The NRC staff finds that the licensee's acceptance examination and associated acceptance criteria are acceptable because they satisfy the requirements of ASME Code, Section III, Subsection ND.

3.2.7 In Service Monitoring

Section 5.d of the relief request states that post-repair monitoring is not possible because the pipe is buried and that the repaired location will be placed into the Seabrook Buried Pipe Inspection Program. In the letter dated September 7, 2012, the licensee clarified that segments of buried piping where internal weld repairs have been performed shall be considered for high prioritization for inspection in the Buried Pipe Inspection Program. The licensee further stated that internal weld repairs may damage the external coating, making the particular segment more susceptible to external induced corrosion, and such are prioritized for future inspection. After installing the encapsulation, the licensee will follow the requirements of the system leakage testing in accordance with the ASME Code, Section XI, IWA-5000 and IWD-5000 for buried piping. The NRC staff finds it is acceptable that the pipe location installed with an encapsulation device will be monitored under the Buried Pipe Inspection Program and that the licensee will perform the system leakage test in accordance with ASME Code, Section XI, IWA-5000 and IWD-5000. As stated above, since welding of the device may affect the exterior coating, the NRC staff permits use of the encapsulation only once at each identified pipe location.

3.2.8 Hardship

In the September 7, 2012, letter, the licensee explained that the act of removing a defect from the inside of the pipe, including drilling a hole and installing a plug, approximately 12 feet below the water table presents an industrial safety risk to individuals performing the repair. Some portions of the pipe are located approximately 25 feet below grade with pipe runs several hundred feet long. Full defect removal creates the potential for groundwater in-leakage into the pipe while the individual is performing the repair and also potentially exposes the individual performing the repair to asbestos from the exterior pipe covering. Excavating the site to repair the pipe represents an undue hardship since some portions of the pipe are located approximately 25 feet below grade and would require extensive excavation to uncover and make the repair. Sections of the pipe are also located adjacent to and below other safety related piping further complicating the excavation and creating the potential to damage safety related piping during the excavation. For these reasons, the licensee states that removal of the defect creates a hardship without a compensating increase in the level of quality or safety. The NRC staff finds that the licensee has provided sufficient and valid hardship argument that an ASME Code repair of the degraded pipe would present hardship and difficulty without a compensating increase in the level of quality and safety.

In summary, the NRC staff finds that the proposed alternative provides adequate technical basis with regard to pre-installation preparation, flaw characterization, design analysis, welding, material selection, acceptance examination, and in-service monitoring. Therefore, the NRC staff finds that the encapsulation device will provide reasonable assurance of structural integrity of the repaired SW piping.

4.0 CONCLUSION

As set forth above, the NRC staff determines that the proposed alternative provides reasonable assurance of structural integrity of the subject SW piping. The NRC staff finds that complying with the specified ASME Code requirement would result in hardship or unusual difficulty without a compensating increase in the level of quality and safety. Accordingly, the NRC staff concludes that the licensee has adequately addressed all of the regulatory requirements set forth in 10 CFR 50.55a(a)(3)(ii) and is in compliance with the requirements of the ASME Code, Section XI, for which the relief was not requested. Therefore, the NRC staff authorizes the use of Relief Request Number RA-12-001, Revision 2, at the Seabrook Station up to two operating cycles (approximately 36 months) from the completion date of the encapsulation device installation for the third 10-year ISI interval which ends on August 18, 2020.

All other ASME Code, Section XI requirements for which relief has not been specifically requested and approved in this relief request remain applicable, including third party review by the Authorized Nuclear Inservice Inspector.

Principal Contributor: J. Tsao, NRR

Date: January 14, 2013

If you have any questions, please contact John G. Lamb at 301-415-3100 or via e-mail at John.Lamb@nrc.gov.

Sincerely,

/RA/

Meena Khanna, Chief
Plant Licensing Branch I-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-443

Enclosure:
Safety Evaluation

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NAME	JLamb	ELee	ABaxter*	DAlley for TLupold*	JHughey for MKhanna
DATE	12/2/12	01/04/13	01/08/13	12/20/12	01/14/13

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