NMC
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Point Beach Nuclear Plant
Operated by Nuclear Management Company, LLC

January 6, 2005

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U.S. Nuclear Regulatory Commission
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Point Beach Nuclear Plant, Units 1 and 2
Dockets 50-266 and 50-301
License Nos. DPR-24 and DPR-27

Response to Request for Additional Information
Regarding the Point Beach Nuclear Plant License Renewal Application
(TAC Nos. MC2099 and MC2100)

By letter dated February 25, 2004, Nuclear Management Company, LLC (NMC), submitted the Point Beach Nuclear Plant (PBNP) Units 1 and 2 License Renewal Application (LRA). On November 18, 2004, the Nuclear Regulatory Commission (NRC) requested additional information regarding the Aging Management Review results for the Steam Generators (Table 3.1.2-5) and several Aging Management Programs (Sections B2.1.7, B2.1.11, B2.1.19, B2.1.22, and B2.1.24). The enclosure to this letter contains the NMC's response to the staff's questions.

On December 1, 2004, the NRC staff verbally provided additional time for NMC to respond to this request for additional information in order for further clarifications to be provided. The clarifications allowed for the NRC staff and the PBNP License Renewal project staff to clearly understand the information needed.

Should you have any questions concerning this submittal, please contact Mr. James E. Knorr at (920) 755-6863.

Summary of Commitments

This letter makes the following new commitment:

> As part of the Steam Generator Integrity Program, visual inspections of accessible areas to verify the integrity of steam generator secondary-side components will be performed at least every six years, with one steam generator being inspected every three years on an alternating basis. Any indications of degradation or unacceptable conditions will be evaluated through the corrective action program, including the extent of condition.

A093

I declare under penalty of perjury that the forgoing is true and correct. Executed on January 6, 2005.

Dennis L. Koehl

Dennis L. Koehl
Site Vice-President, Point Beach Nuclear Plant
Nuclear Management Company, LLC

Enclosure

cc: Administrator, Region III, USNRC
Project Manager, Point Beach Nuclear Plant, USNRC
Resident Inspector, Point Beach Nuclear Plant, USNRC
PSCW

## ENCLOSURE

## RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION REGARDING POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2 LICENSE RENEWAL APPLICATION

The following information is provided in response to the Nuclear Regulatory Commission (NRC) staff's request for additional information (RAI) regarding the Point Beach Nuclear Plant (PBNP) License Renewal Application.

The NRC staff's questions are restated below, with the Nuclear Management Company (NMC) response following.

**Aging Management Review Program - Steam Generator Aging Management**

**NRC Question RAI 3.1-1:**

Table 3.1.2-5 identifies that aging will be managed for the SG Anti-Vibration Bars (AVBs) by the Water Chemistry Program and the Steam Generator Integrity Program for cracking due to SCC. Table 3.1.2-5 also refers to NUREG 1801, Volume 2, line item (IV.D1.2-h) and table 1 line item (3.1.1-19) which refer to loss of material associated with FAC for this line item. Provide an explanation for the discrepancy between the aging effect identified in the license renewal application and what is identified in GALL (including the further evaluation section of the LRA) and provide any corrections. Discuss how SG secondary-side inspections will be used to assess degradation in the AVBs in light of the ten elements of an AMP.

**NMC Response:**

Section 3.0.2 of the LRA, under "Table Usage" (see pages 3-12 through 3-13), stated that when a PBNP table 2 line item was not entirely consistent with the equivalent GALL line item, parentheses would be used around the GALL reference(s) and further explanation would be included in the "Notes." In the case of the AVBs, parentheses were used, and Notes F and H indicated that the material and aging effect were different than what was identified in GALL. Additionally, the "Discussion" column of table 1, line item 3.1.1-19, references the further evaluation documented in Section 3.1.2.2.12 of the LRA. This LRA section states:

> "Tube support lattice bars are fabricated from either stainless steel or Alloy 600 in the PBNP replacement steam generators. These materials are not susceptible to FAC. However, these materials are susceptible to cracking, which is managed by the Water Chemistry Control Program, and augmented by the Steam Generator Integrity Program, which provides for secondary-side inspections to verify the effectiveness of water chemistry control."

The Steam Generator Integrity Program (LRA Section B2.1.19) is used in conjunction with the Water Chemistry Control Program (LRA Section B2.1.24) to manage cracking due to stress corrosion cracking (SCC) for the AVBs. The Water Chemistry Control Program conforms to the guidelines in EPRI TR-102134, Rev. 5. The Water Chemistry Control Program mitigates aging effects, such as cracking due to SCC, by controlling the environment to which the secondary-side of the steam generators are exposed. Aging effects are minimized by controlling the chemical species that cause the underlying mechanisms that result in this aging effect. The program provides assurance that an elevated level of contaminants and oxygen are limited on the secondary-side of the steam generators, and thus minimizes the occurrences of this aging effect. A water chemistry control program has been in use since early plant operation and has been effective at maintaining the desired system water chemistry and detecting abnormal conditions, which have been corrected in an expedient manner. No verification inspections are required by the Water Chemistry Control Program since the secondary-side of the steam generators is not a low flow or stagnant area. Therefore, the Water Chemistry Control Program alone effectively manages this aging effect on the secondary-side of the steam generators. However, NMC conservatively included the Steam Generator Integrity Program to augment the Water Chemistry Control Program to verify the effectiveness of water chemistry control. The internal secondary-side inspections credited within the Steam Generator Integrity Program would be used to provide this verification.

The overall intent of crediting the Steam Generator Integrity Program is that it can provide a general condition assessment of the internal surfaces within the secondary-side of the steam generators. The program includes the inspection of various secondary-side internal components, including those important for ensuring tube integrity. Although the AVBs are inaccessible for visual inspection due to the construction of the tube bundle and their location within the tube bundle, periodic visual inspections of accessible areas are performed to verify the integrity of secondary-side components. This is acceptable since the materials and environment (i.e., potential aging effects) of the accessible subcomponents are representative of any inaccessible subcomponents. The inspections include portions of the upper tube bundle, tube support plates, swirl vane, moisture separator, and feed ring areas. Upper tube bundle inspections are performed at least every six years, with one steam generator being inspected every three years on an alternating basis. If signs of tube support plate degradation are detected, additional visual inspections are performed to determine the extent of the damage. These periodic visual inspections of secondary-side components provides reasonable assurance that degradation will be detected before the loss of any intended function or the integrity of the steam generator tubes is challenged. In addition, the Steam Generator Integrity Program includes steam generator tube eddy current testing that would detect any tube wear that may occur as a result of any cracking due to SCC in the AVBs.

As noted in Section B2.1.19 of the LRA, enhancements to the Steam Generator Integrity Program include plant procedure revisions to specify the inspection of additional secondary-side components, provide acceptance criteria, and improve inspection documentation. As part of the Steam Generator Integrity Program, visual inspections of accessible areas to verify the integrity of steam generator secondary-side components will be performed at least every six years, with one steam generator being inspected every three years on an alternating basis. Any indications of degradation or unacceptable conditions will be evaluated through the corrective action program, including the extent of condition. These enhancements will be developed and scheduled for completion prior to the period of extended operation.

**NRC Question RAI 3.1-2:**

Table 3.1.2-5 identifies that aging management for a number of steam generator secondary-side components which are identified as susceptible to loss of material will be provided by both the Water Chemistry Program and Steam Generator Integrity Program. Table 3.1.2-5 also associates NUREG 1801 Volume 2 line item (IV.D1.1-c) and table 1 line item (3.1.1-02) with these components which identifies that the Inservice Inspection Program along with Water Chemistry will be used to manage aging. The further evaluation (item 3.1.2.2.2.1) associated with (3.1.1-02) for these items indicates Inservice Inspection and Water Chemistry will manage aging for these components and that the Steam Generator Integrity Program will provide all inclusive guidance for the management of Steam Generator assets. The Steam Generator Integrity Program description does not indicate that it will be used to meet the intent of the Inservice Inspection program for certain components. Clarify if the SG Integrity Program is intended to subsume the Inservice Inspection activity and manage aging of these components, why Inservice Inspection is not addressed in table 3.1.2-5 for these components and how the Steam Generator Integrity Program will manage aging for these components with particular focus being paid to addressing detection, monitoring and trending, acceptance criteria and operating experience with past secondary-side inspections associated with these components. Also address how loss of material, pitting and crevice corrosion of the shell and its components will be identified by these secondary-side inspections.

SG Blowdown Piping Nozzles and Secondary Shell Penetration
SG Feedwater Nozzle
SG Secondary Closures
SG Steam Outlet Nozzle
SG Tube Bundle Wrapper and Wrapper Support System
SG Tubesheet
SG Upper and Lower Shell, Elliptical Head and Transition Cone

**NMC Response:**

The Steam Generator Integrity Program is in no way intended to subsume the inservice inspection activity for any components or subcomponents. As stated in LRA

Section 3.1.2.2.2.1, the Steam Generator Integrity Program is intended to augment the Water Chemistry Control Program and the Inservice Inspection Program.

The overall intent for using the Steam Generator Integrity Program is that it can provide a more thorough assessment of internal surfaces within the secondary-side of the steam generator. An inservice inspection exam typically only evaluates condition at the area of interest around the weld, where the Steam Generator Integrity Program inspections will provide a more general inspection of internal surfaces within the steam generator. Note that for steam generator components that are within the scope of the existing inservice inspection plan (e.g., Feedwater Nozzle, Steam Outlet Nozzle, Tubesheet, and Upper and Lower Shell, Elliptical Head and Transition Cone), the Inservice Inspection Program is credited for managing cracking due to flaw growth on these components. This aging effect is not identified in GALL, but it is the primary aging effect that these inservice inspection exams are looking for. While these exams will detect loss of material due to corrosion, their primary purpose is to identify cracking. Notice that on each of these components, Note 23 was used, which expresses this reasoning and why the Steam Generator Integrity Program was credited.

Some components are not within the scope of the existing inservice inspection plan (e.g., Blowdown Piping Nozzles and Secondary Shell Penetration, Secondary Closures, and Tube Bundle Wrapper and Wrapper Support System), and therefore do not require any inservice inspection exams for these components. Since no inservice inspection exams are performed for these components, the Inservice Inspection Program is not credited for managing any aging effect for these components in Table 3.1.2.-5. Therefore, the Steam Generator Integrity Program was credited, as it provides for visual inspections of various internal secondary-side surfaces. Notice that on each of these components, Note 20 was used, which expresses this reasoning.

Program attributes for the Steam Generator Integrity Program are included in Section B2.1.19 of the LRA. Included within this program description are the secondary-side visual inspections which are expected to help provide the aging management of the above components. Refer to the NMC Response to NRC Question RAI 3.1-5 for a description of how the Water Chemistry Control Program and Steam Generator Integrity Program are credited for managing the aging of these components.

<u>NRC Question RAI 3.1-3</u>:

Table 3.1.2-5 indicates that SG Components (in contact with primary water) fabricated from stainless steel, alloy 600 and alloy 690 are susceptible to loss of material and the aging will be managed by Water Chemistry alone. Since water chemistry is a mitigative strategy and inspection is used (one time inspection at a minimum) to verify its effectiveness, provide a list of the subject subcomponents and provide an explanation why water chemistry alone is sufficient to manage aging in these subcomponents based on specific operating experience or past inspection results of these subcomponents demonstrating the effectiveness of water chemistry.

**NMC Response:**

The list of subject subcomponents is any of the Component Types listed in LRA Table 3.1.2-5, that have an internal environment of "Treated Water – Primary." This includes the Divider Plate, the Primary Channel Head, the Primary Inlet and Outlet Nozzle Safe Ends, the Primary Inlet and Outlet Nozzles, the Primary Manways, and the Tubesheet.

In GALL Table D1, "Steam Generator (Recirculating)," none of the line items that are applicable to the primary-side components address loss of material (see GALL Volume II, line items D1.1-i and D1.1-j). Loss of material was included as an aging effect because without water chemistry controls, loss of material could occur. The inclusion of this single line item was intended to show acknowledgement of this, and take credit for water chemistry to manage loss of material for any components in contact with primary coolant.

The GALL program description for XI.M2, "Water Chemistry," states the following:

> "The water chemistry programs are generally effective in removing impurities from intermediate and high flow areas. The Generic Aging Lessons Learned (GALL) report identifies those circumstances in which the water chemistry program is to be augmented to manage the effects of aging for license renewal. For example, the water chemistry program may not be effective in low flow or stagnant flow areas. Accordingly, in certain cases as identified in the GALL report, verification of the effectiveness of the chemistry control program is undertaken to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period of operation. As discussed in the GALL report for these specific cases, an acceptable verification program is a one-time inspection of selected components at susceptible locations in the system."

Therefore, typically one-time inspections are required to verify the effectiveness of water chemistry control in low flow or stagnant areas. The primary-side of the steam generators is not a low flow or stagnant area.

Additionally, please note that most of the primary-side components are also managed for cracking, which credits the Water Chemistry Program and the Inservice Inspection Program to manage this aging effect. As such, inservice inspection exams are performed on primary-side components, which would indicate if loss of material were occurring. Also, during eddy-current inspection set-ups and take-downs, informal visual inspections are performed of the primary-side of the steam generators. All of our plant-specific operating experience shows that water chemistry alone is adequately managing loss of material, and no additional inspections to verify this are warranted.

**NRC Question RAI 3.1-4:**

Table 3.1.2-5 indicates that the SG Divider Plate which is fabricated from alloy 600 and alloy 690 is susceptible to stress corrosion cracking and the aging will be managed by water chemistry alone. Since water chemistry is a mitigative strategy and inspection is used (one time inspection at a minimum) to verify its effectiveness, provide an explanation why water chemistry alone is sufficient to manage aging in these components based on specific operating experience or past inspection results that demonstrate the effectiveness of water chemistry.

**NMC Response:**

The steam generator divider plates do not perform a Reactor Coolant System (RCS) pressure boundary function. The divider plate is simply a 2-inch thick baffle, internal to the steam generator channel head, provided to direct RCS flow through the steam generator tubes. The normal operating differential pressure across the divider plate is small (< 50 psig). The resulting primary stresses are minimal. Thermal stresses are the main contributor to the operating stresses in the divider plate.

There is no industry operating experience indicating problems with stress corrosion cracking (SCC) of the steam generator divider plate. A catastrophic failure would be required to affect the divider plate's baffle function. It is extremely unlikely that SCC would result in a loss of the divider plate's baffle function. Any significant steam generator divider plate degradation would be evident during normal steam generator channel head activities associated with steam generator tube inspections. Even though inspections could be performed in conjunction with steam generator tube inspection activities, there would be dose consequences associated with performing the inspection due to the dose environment of the steam generator channel head.

In view of the above, and that Water Chemistry alone has historically proven effective in managing SCC of the steam generator divider plates, additional aging management activities for SCC of the steam generator divider plate are not warranted.

**NRC Question RAI 3.1-5:**

Clarify the SG program scope to identify those subcomponents that rely on this program for aging management. Discuss the periodicity, acceptance criteria and bases for these items associated with the secondary-side SG inspections for the various subcomponents which rely on this program for aging management.

**NMC Response:**

The primary purpose of the Steam Generator Integrity Program (LRA Section B2.1.19) is to manage aging effects associated with the steam generator U-tubes and plugs.

However, the program is also used to credit secondary-side inspections within the steam generators. The steam generator subcomponents (other than the U-tubes and plugs) that credit the Steam Generator Integrity Program are identified in Table 3.1.2-5 of the LRA (see pages 3-116 through 3-123). These subcomponents are:

1. SG Anti-Vibration Bars
2. SG Blowdown Piping Nozzles and Secondary-Side Shell Penetrations
3. SG Feedwater Nozzle
4. SG Secondary Closures
5. SG Steam Outlet Nozzle
6. SG Transition Cone Girth Weld
7. SG Tube Bundle Wrapper and Wrapper Support System
8. SG Tube Support Plates
9. SG Tubesheet
10. SG Upper and Lower Shell, Elliptical Head and Transition Cone

The Steam Generator Integrity Program is used in conjunction with the Water Chemistry Control Program (LRA Section B2.1.24) to manage loss of material and/or cracking due to stress corrosion cracking (SCC) for these subcomponents. The Water Chemistry Control Program conforms to the guidelines in EPRI TR-102134, Rev. 5. The Water Chemistry Control Program mitigates aging effects, such as loss of material and cracking due to SCC, by controlling the environment to which the secondary-side of the steam generators are exposed. Aging effects are minimized by controlling the chemical species that cause the underlying mechanisms that result in these aging effects. The program provides assurance that an elevated level of contaminants and oxygen do not exist on the secondary-side of the steam generators, and thus minimizes the occurrences of these aging effects. A water chemistry control program has been in use since early plant operation and has been effective at maintaining the desired system water chemistry and detecting abnormal conditions, which have been corrected in an expedient manner. No verification inspections are required by the Water Chemistry Control Program, since the secondary-side of the steam generators is not a low flow or stagnant area. Therefore, the Water Chemistry Control Program alone effectively manages these aging effects on the secondary-side of the steam generators. However, NMC conservatively included the Steam Generator Integrity Program to augment the Water Chemistry Control Program to verify the effectiveness of water chemistry control. The internal secondary-side inspections credited within the Steam Generator Integrity Program would be used to provide this verification.

The Steam Generator Integrity Program is also used in conjunction with the Flow Accelerated Corrosion Program (LRA Section B2.1.11) to manage loss of material due to flow accelerated corrosion (FAC) for the Feedwater Nozzle. The Flow Accelerated Corrosion Program manages aging effects due to FAC on the internal surfaces of carbon or low alloy steel components. The program includes: (a) an analysis using a predictive code to determine critical locations, (b) baseline inspections to determine the extent of thinning at these locations, (c) follow-up inspections to confirm predictions, and

(d) repairing or replacing components, as necessary. The objectives of this program are to control and monitor FAC, to plan inspections, to prevent failures, and to implement a long-term strategy to reduce loss of material due to FAC. Therefore, the Flow Accelerated Corrosion Program alone effectively manages this aging effect on the Feedwater Nozzle. This is consistent with the GALL, which only recommends the Flow Accelerated Corrosion Program for managing this aging effect. However, NMC conservatively included the Steam Generator Integrity Program to augment the Flow Accelerated Corrosion Program to verify the presence or absence of FAC on internal surfaces of the steam generators. The internal secondary-side inspections credited within the Steam Generator Integrity Program would be used to provide this verification.

The overall intent of crediting the Steam Generator Integrity Program is that it can provide a general condition assessment of the internal surfaces within the secondary-side of the steam generators. The program includes the inspection of various secondary-side internal components, including those important for ensuring tube integrity. Although it is recognized that not all of the above listed subcomponents may be accessible, periodic visual inspections of accessible areas are performed to verify the integrity of secondary-side components. This is acceptable since the materials and environment (i.e., potential aging effects) of the accessible subcomponents are representative of any inaccessible subcomponents. The inspections include portions of the upper tube bundle, tube support plate, swirl vane, moisture separator, and feed ring areas. Upper tube bundle inspections are performed at least every six years, with one steam generator being inspected every three years on an alternating basis. If signs of tube support plate degradation are detected, additional visual inspections are performed to determine the extent of the damage. These periodic visual inspections of secondary-side components provides reasonable assurance that degradation will be detected before the loss of any intended function or the integrity of the steam generator tubes is challenged.

As noted in Section B2.1.19 of the LRA, enhancements to the Steam Generator Integrity Program include plant procedure revisions to specify the inspection of additional secondary-side components, provide acceptance criteria, and improve inspection documentation. As part of the Steam Generator Integrity Program, visual inspections of accessible areas to verify the integrity of steam generator secondary-side components will be performed at least every six years, with one steam generator being inspected every three years on an alternating basis. Any indications of degradation or unacceptable conditions will be evaluated through the corrective action program, including the extent of condition. These enhancements will be developed and are scheduled for completion prior to the period of extended operation.

**NRC Question RAI 3.1-6:**

The SG Integrity Program AMP related operating experience acknowledges the Outside Diameter Stress Corrosion Cracking (ODSCC) that was identified at Seabrook and indicates that the Point Beach Nuclear Power Plant SG tube material is thermally treated alloy 600 in Unit 1 and thermally treated Alloy 690 in Unit 2. Provide an operating experience discussion regarding inspections and results performed at Point Beach Units 1 & 2 to identify if similar tube eddy current characteristics exist as those identified at Seabrook and documented in Supplement 1 of NRC Information Notice 2002-21.

**NMC Response:**

The Seabrook and Braidwood steam generators have experienced ODSCC (Outer Diameter Stress Corrosion Cracking) at support plates in tubes which apparently had elevated residual stresses due to a flaw in the tubing manufacturing process. These plants have Inconel 600TT tubing material in their steam generators.

The Seabrook experience suggests that under some circumstances, Alloy 600TT tubing in quatrefoil tube support plate (TSP) configurations is susceptible to ODSCC. The tubing in PBNP Unit 1 is also Alloy 600TT. Therefore, axial ODSCC at supports was considered a potential degradation mechanism in the PBNP Unit 1 Steam Generator Degradation Assessment. The tubing in PBNP Unit 2 is Alloy 690TT which is considered more resistant to ODSCC than Alloy 600TT. Therefore, it is unlikely that PBNP Unit 2 tubing will experience similar degradation. As a precaution, however, axial ODSCC at supports was considered a potential degradation mechanism in the PBNP Unit 2 Steam Generator Degradation Assessment.

In view that the PBNP Unit 1 steam generators have Alloy 600TT tubing, Westinghouse performed a special analysis on the 2001 PBNP Unit 1 steam generator inspection bobbin data which included voltage measurements made at all tangents above row 8 and an observation for drift on the absolute channels on rows 8 and lower. The purpose of this special analysis was to enable Westinghouse to identify any tubes which could have a higher susceptibility to ODSCC due to a flaw in the manufacturing process of the tubes. As a result of this special analysis, there were 98 total tubes identified as having a possible higher susceptibility to ODSCC at the support plates. The PBNP Unit 1 refueling outage 28 (spring 2004) steam generator inspection consisted of a 100% bobbin coil inspection with a rotating coil used for special interest areas. These 98 tubes were tested during this steam generator inspection with bobbin coils. These tubes were then analyzed with a heightened sensitivity to support plate ODSCC by the analysts. No bobbin indications were reported at a support plate on any of these tubes.

In view that the PBNP Unit 2 steam generators contain a material that is more resistant to SCC, coupled with a lack of industry experience indicating that the problem is even applicable to Alloy 690TT, no special offset evaluation was performed to identify tubes potentially susceptible to ODSCC. The PBNP Unit 2 refueling outage 26 (fall 2003) steam generator inspection consisted of a 50% bobbin coil inspection with a rotating coil used for special interest areas. No bobbin indications were reported at a support plate on any of these tubes.

## Aging Management Program B2.1.7 - Buried Services Monitoring Program

### NRC Question RAI 2.1.7.-1:

The program indicates that buried components within the program scope are coated per industry practice prior to installation. Although the AMP references "industry practice" what bases were used by the plant to confirm that all buried services within the program scope were required to be coated at the plant? If such documentation does not exist, how is reasonable assurance established that program components are all coated in light of the limited related operating experience.

### NMC Response:

Piping classification specifications used for design and installation of service water and fuel oil piping systems at PBNP, specify coatings and wrappings to be used for buried pipe. Plant-specific Operating Experience (OE) indicates that Service Water (SW) and Fuel Oil (FO) piping that was unearthed in the course of a construction project, was found to be coated/wrapped. This provides reasonable assurance that these buried piping systems are coated/wrapped.

Fire protection piping has been coated per "industry practice," which allows for installation without a protective coating system if the soil is not aggressive. PBNP's soil/ground water and lake water environmental conditions have been shown to be non-aggressive (see Plant-Specific Response to Applicant Action Item #12 in Table 3.5.0-1 of the LRA). This condition was evidenced by plant specific OE, where fire protection piping that was unearthed after 14 years of operation was found to only have a light bituminous asphaltic coating (typically used only to prevent surface oxidation before the pipe is buried). However, this pipe was found be in excellent (like-new) condition with no external surface degradation evident.

NUREG-1801 provides guidance for determining whether aggressive chemical attack is an environment of concern. This guidance includes threshold values for the pH and chloride and sulfate concentrations of the environment. The environments of concern are below-grade (as influenced by soil/ground water) and lake water. According to NUREG-1801, aggressive chemical attack is not significant if the component is not exposed to an aggressive environment. An aggressive environment is defined as pH < 5.5, or > 500 ppm chlorides, or > 1500 ppm sulfates. The below-grade and lake water environments, as determined from periodic tests of ground water and lake water at PBNP, are significantly less severe than the NUREG-1801 values. Therefore, the environmental conditions that underground buried pipe at PBNP is exposed to is classified as non-aggressive.

NUREG-1801, Section XI.M34, "Buried Piping and Tanks Inspection," states that underground piping is coated during installation with a protective coating system to protect the piping from contacting the aggressive soil environment in accordance with "industry practice." As stated above, underground fire protection piping at PBNP appears to have been coated per "industry practice," which allows for installation without a protective coating system if the soil is not aggressive. Therefore, the underground fire protection piping at PBNP is coated in accordance with "industry practice." This is acceptable based upon the following:

- PBNP's soil/ground water and lake water environmental conditions have been shown to be non-aggressive (see Plant-Specific Response to Applicant Action Item #12 in Table 3.5.0-1 of the LRA).

- Periodic chemical analyses of the soil/ground water, and lake water will be performed to ensure that the below-grade environment remains chemically non-aggressive for the period of extended operation [LRA Section 3.0.1.9 (Page 3-7)].

- PBNP has almost 34 years of operating experience with buried components, during which there have been no failures of buried components within the scope of license renewal in the Fire Water system due to external surface degradation.

- Discussions with the PBNP Fire Protection System Engineer indicate that buried Fire Water system piping has been excavated at least seven times since the early 1980's, such that buried Fire Water system piping was excavated on an average of every three to four years. In each of these cases, no external surface degradation of the buried Fire Water system piping was documented.

- Fire protection piping that was unearthed after 14 years of operation with only a light bituminous asphaltic coating (typically used only to prevent surface oxidation before the pipe is buried) was found be in excellent (like-new) condition, with no external surface degradation evident.

- The Fire Protection Program (LRA Section B2.1.10) continuously monitors fire water system pressure through alarm setpoints. The Fire Protection Program also includes monthly visual inspections of fire hydrants and annual fire hydrant flow tests. These activities provide an opportunity for degradation of the underground fire protection piping to be detected before a loss of intended function can occur.

All of the above provides reasonable assurance that buried pipe that is within the scope of license renewal, whether or not it is coated, can be adequately managed by the Buried Services Monitoring Program, through the period of extended operation.

**NRC Question RAI 2.1.7.-2:**

Related operating experience indicates that a post-indicating valve was repaired in the fire protection system which required excavation, exposing portions of the associated piping. The operating experience also indicates that the external portion of the piping showed no signs of corrosion after 14 years. Please discuss how the specific condition assessment of the piping corrosion (or lack of) was made in light of the program element that buried components are coated per industry practice; i.e., was the piping coated and was the coating removed to make this assessment?

**NMC Response:**

A post-indicating valve was repaired in the Fire Protection System in June 2002. This repair required the ground to be excavated for valve removal, which exposed buried portions of the valve and Fire Protection System piping. The piping in the vicinity of the valve was visually inspected by the Fire Protection System Engineer. This piping was coated with a thin tar-like (bituminous asphaltic) coating with some isolated areas where the base metal of the piping was exposed, and that the external surface of the piping "looked like new and showed no signs of degradation." This visual inspection included piping areas that were coated, as well as, areas where the base metal of the piping was exposed. Removal of the thin layer coating was not necessary. The valve and piping were installed in 1988. Therefore, the external surface of the piping showed no signs of degradation after being buried for almost 14 years.

The Buried Services Monitoring Program is a new program that includes: (a) preventive measures to mitigate degradation (e.g., external coatings and wrappings), and (b) visual inspections of external surfaces of buried components for evidence of coating damage and substrate degradation to manage the effects of aging. The program monitors parameters such as coating and wrapping integrity that are directly related to the effects of aging on the external surfaces of buried components. Inspections of buried components are performed to confirm that coatings and wrappings are intact to ensure that age-related degradation of external surfaces has not occurred and that the intended function of the components is maintained. Coating and wrappings are visually inspected for evidence of damage, such as coating perforation, holidays, or other damage that will cause the protected components to be inspected for evidence of degradation. If the visual inspection shows that the coatings or wrappings are intact, no further inspection is required. However, if any evidence of damage is observed or the piping is not coated, the components will be further inspected for evidence of degradation.

**NRC Question RAI 2.1.7.-3:**

Since this is a new program, it is understandable that there may be limited operating experience regarding inspections of opportunity which validate the limited buried component degradation. However, the GALL indicates that inspection periodicity needs to be evaluated on a plant specific bases. With such a limited amount of experience, provide a justification why one time inspection of various in-scope components is not warranted prior to the period of extended operation to establish a sound basis for inspection frequency or to justify why inspections of opportunity will adequately manage aging in the future.

**NMC Response:**

Although the Buried Services Monitoring Program is a new program, PBNP has almost 34 years of operating experience with buried components. During that time, there have been no failures of buried components within the scope of license renewal in the Service Water, Fuel Oil, or Fire Water systems due to external surface degradation. Discussions with the PBNP Fire Protection System Engineer also indicate that buried Fire Water system piping has been excavated at least seven times since the early 1980's, such that buried Fire Water system piping was excavated on an average of every three to four years. In each of these cases, no external surface degradation of the buried Fire Water system piping was documented. This is primarily due to preventive measures to mitigate degradation (e.g., external coatings and wrappings), non-aggressive soil/ground water and lake water environmental conditions at PBNP. This is supported by the examples of plant-specific operating experience discussed in Section B2.1.7 of the PBNP LRA (see pages B-78 and B-79). In addition, as noted in Section 3.0.1.9 of the PBNP LRA (page 3-7), periodic chemical analyses of the soil/ground water and lake water will be performed to ensure that the below-grade environment remains chemically non-aggressive for the period of extended operation. Therefore, one-time inspection of various in-scope components is not warranted prior to the period of extended operation. Inspections will be performed based on plant operating experience and opportunities for inspection. As additional operating experience is obtained, lessons learned may be used to adjust the basis of this program.

**Aging Management Program B2.1.22 - Tank Internal Inspection Program**

**NRC Question RAI 2.1.22-1:**

The Tank Internal Inspection Program indicates that the internal surfaces of carbon steel tanks will be periodically visually inspected and UT will be used to inspect inaccessible areas, such as the tank bottom or may be used from external surfaces. Provide a discussion regarding the periodicity and its bases for internal visual inspection and UT inspection of the tank bottoms. Discuss the inspection scope for internal visual, UT of the tank bottom and when external UT is used, for instance, will internal visual inspection consist of 100% of the tank surface area, will the tank bottom UT consist of 100% of the bottom surface and if 100% inspection is not performed discuss the bases for a reduced inspection scope and the associated expansion criteria. Discuss how external UT examination scope will be comparable to internal visual examination scope when external UT inspection is used in lieu of internal inspection. If a sampling strategy is used in any of the above inspections provide a discussion of the sampling plan and its bases.

**NMC Response:**

The only components that rely on the Tank Internal Inspection Aging Management Program (AMP) for aging management are the Condensate Storage Tanks (CST) and the starting air receivers for G-01 and G-02 Emergency Diesel Generators.

Existing visual inspections of the CSTs occur at four to five year intervals. As part of the Tank Internal Inspection Program, Ultrasonic Testing (UT) inspection of the tank bottom will be performed prior to entry into the period of extended operation. The interval of the periodic inspections (visual and UT) required for aging management will be determined based on the results of the initial UT inspection. Visual inspections will be performed on 100% of the internal surfaces. UT examinations will not generally cover 100% of the tank bottom but will inspect a representative sample of the entire tank bottom through the application of a grid system of inspection locations. The grid size, determined by Engineering judgment (e.g., 12" by 12"), is based on no known degradation; however, if areas of degradation are noted, then smaller grids will be necessary to determine the extent of degraded area. This will provide a reasonable assurance of detection of thinning due to corrosion. If degradation is detected, additional UT thickness measurements will be performed as necessary to determine the size of the area of degradation.

Inspections of the G-01 and G-02 Emergency Diesel Generator starting air receivers are performed at three year intervals to satisfy Wisconsin Administrative Code requirements for pressure vessels. Limited UT thickness measurements and video probe inspections of the lower portions of the air receivers performed in 2002 and 2003 revealed no adverse conditions. Measured thicknesses were comparable to the nominal thickness of 0.25". Based on the results of these inspections, a three year inspection interval is considered to be adequate for aging management. As part of the Tank Internal Inspection Program internal visual inspections of these pressure vessels will be performed with a boroscope or video probe via a small access opening. While this allows the performance of a reasonable visual inspection of the internal surfaces of the bottom of the pressure vessel, the remaining portions of the vessel are not practical to exam in this manner due to the restricted access. The sides and top of the vessel will be spot checked for wall thickness using UT methods. Spot checking is adequate because the most severe corrosion is expected to occur on the bottom of the vessel due to condensation and would be detected by the visual inspection. If the UT spot checking detects any loss of material, the inspection area will be expanded as needed to determine the size of the area of degradation. UT will also be used to determine the thickness of the vessel bottom if the visual inspection detects significant corrosion resulting in a loss of material.

**NRC Question RAI 2.1.22-2:**

*Since monitoring and trending will only commence if significant wall loss is identified, how will it be possible to know the areas monitored if 100% inspection is not performed every time and how will accurate rates of degradation be determined which could be used to establish alternate inspection frequencies as outlined in the program description. The Acceptance Criteria indicates that "Any degradation will be recorded and evaluated..." this appears to be a form of monitoring and trending, discuss the apparent discrepancy.*

**NMC Response:**

Monitoring will be accomplished as part of the periodic inspections. Procedures will provide for trending if there is any detectible thinning of the tank bottom or walls. Visual inspections will cover 100% of the tank bottom and wall of the CSTs and 100% of the bottom of the starting air receivers. UT examinations will not generally cover 100% of the tank bottom or wall, but will inspect a representative sample of the tank bottom or wall through the application of a grid system of for the bottom of the CSTs and by spot checking the sides and top of the starting air receivers. While all degradation will be documented and evaluated against the acceptance criteria, trending of degraded areas will commence when loss of material is detected but has not yet exceeded the acceptance criteria. The trending will provide information allowing more accurate determination of the rate of degradation.

**NRC Question RAI 2.1.22-3:**

*Define what is considered significant coating degradation which would lead to corrective action or significant material loss which would lead to commencement of trending. How will loss of material be measured/evaluated when visual inspection is performed to determine level of significance. Discuss how loss of material from general corrosion, pitting or underdeposit attack would be addressed relative to significant material loss and acceptance criteria.*

**NMC Response:**

Significant coating degradation is considered to be any degradation that exposes bare metal surfaces of tank interior. Significant material loss requiring the commencement of trending is considered to be any detectable reduction in the thickness of the tank bottom or side walls as this may be indicative of an active corrosion mechanism. Loss of material from general corrosion, pitting or underdeposit attack will be detected during visual inspections by any obvious discontinuities in the level of the material surface. If observed areas of corrosion are of such size or location as to make surface level comparisons impractical, UT measurements will be taken to determine the material thickness in accordance with the requirements of the Tank Internal Inspection Program. Any degradation of carbon steel tank internal surfaces will be evaluated to ensure that the minimum wall thickness is maintained until the next scheduled inspection. Thickness measurements of inaccessible tank bottoms and walls are evaluated against the design thickness.

**NRC Question RAI 2.1.22-4:**

Based on the related operating experience, tank internal inspections of the North and South Condensate Tanks have occurred, did these inspections include UT of the tank bottoms. If the tanks bottoms were not evaluated when will the tank bottoms be evaluated and what was the justification for not evaluating the bottoms. Had these tanks ever been recoated in the life of the plant and when was the previous inspection of each of these tanks.

**NMC Response:**

Inspections of the Condensate Storage Tanks (CST) referenced in the LRA did not include UT of the tank bottoms because the intent of past inspections was to assess the conditions of the internal surfaces of the tank only and this could be accomplished satisfactorily with visual inspections. Upon implementation of the Tank Internal Inspection AMP, CST inspections will include UT inspections of the tank bottom as a means to monitor for any significant corrosion (i.e. resulting in detectable thinning of the bottom plate) that may be occurring on the external surface of the tank bottom. To the best of our knowledge, the CSTs have never been recoated. The previous inspections occurred in 1994, 2000, and 2002 for T-24A and 1994, 2001, and 2002 for T-24B.