PrairieIslandNPEm Resource

From: Vincent, Robert [Robert.Vincent@xenuclear.com]
Sent: Tuesday, January 20, 2009 6:33 PM
To: Richard Plasse; Nathan Goodman; Stuart Sheldon
Cc: Eckholt, Gene F.; Davis, Marlys E.
Subject: PINGP Letter Responding to NRC RAIs Dated 12-18-09
Attachments: 20090920 Response to NRC RAI Letter dtd 12-18-08.pdf; 20090920 Response to NRC RAI Letter dtd 12-18-08.doc

Attached are pdf and WORD versions of the NSPM letter responding to the AMR RAIs dated 12-18-09. Note that we have changed one commitment, so a complete copy of the updated commitment list is also attached.

Let me know if you have any problems with the files.

Bob Vincent
Licensing Lead, License Renewal Project
651-388-1121 X7259

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Responses to NRC Requests for Additional Information Dated December 18, 2008 Regarding Application for Renewed Operating Licenses

By letter dated April 11, 2008, Northern States Power Company, a Minnesota Corporation, (NSPM) submitted an Application for Renewed Operating Licenses (LRA) for the Prairie Island Nuclear Generating Plant (PINGP) Units 1 and 2. In a letter dated December 18, 2008, the NRC transmitted Requests for Additional Information (RAIs) regarding that application. This letter provides responses to those RAIs.

Enclosure 1 provides the text of each RAI followed by the NSPM response.

Enclosure 2 provides an updated version of the Preliminary License Renewal Commitment List contained in the LRA transmittal letter. This updated list reflects changes made to date in the various NSPM letters responding to NRC RAIs.

If there are any questions or if additional information is needed, please contact Mr. Eugene Eckholt, License Renewal Project Manager.

Summary of Commitments

This letter contains no new commitments. Commitment No. 6 in the list of Preliminary License Renewal Commitments contained in the LRA transmittal letter dated April 11, 2008, is revised to read as follows:

> The Closed-Cycle Cooling Water System Program will be enhanced to include periodic inspection of accessible surfaces of components serviced by closed-cycle cooling water when the systems or components are opened during scheduled maintenance or surveillance activities. Inspections are performed to identify the presence of aging effects and to confirm the effectiveness of the chemistry controls. Visual inspection of component internals will be used to detect loss of material and heat transfer degradation. Enhanced visual or volumetric examination techniques will be used to detect cracking.

I declare under penalty of perjury that the foregoing is true and correct.
Executed on January 20, 2009.

Michael D. Wadley
Site Vice President, Prairie Island Nuclear Generating Plant Units 1 and 2
Northern States Power Company - Minnesota

Enclosures (2)

cc:

Administrator, Region III, USNRC
License Renewal Project Manager, Prairie Island, USNRC
Resident Inspector, Prairie Island, USNRC
Prairie Island Indian Community ATTN: Phil Mahowald
Minnesota Department of Commerce

Enclosure 1
NSPM Responses to NRC Requests for Additional Information
Dated December 18, 2008

RAI 3.1.1-1

In LRA Table 3.1.2-03, two AMR line items references the following:

- Table 1 item 3.1.1-80 and GALL Report Volume 2 line item IV.B2-21

For these line items, the GALL Report recommends that AMP XI.M13, “Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS),” be used for managing the aging effects of loss of fracture toughness due to thermal aging and neutron irradiation embrittlement. However Table 1 item 3.1.1-80 credits the PINGP B2.1.32, “PWR Vessels Internal Program.” Please justify the basis for using the PINGP AMP B2.1.32, “PWR Vessels Internal Program,” in lieu of the GALL Report recommended program.

NSPM Response to RAI 3.1.1-1

The NUREG-1801, XI.M13 Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program consists of two major parts:

- Initially the program requires the identification of susceptible components determined to be limiting from the standpoint of thermal aging susceptibility based on ferrite and molybdenum contents, casting process, and operating temperature; and/or neutron irradiation embrittlement (neutron fluence). Note that the material composition of the PINGP CASS BMI Column Cruciforms could not be determined, and therefore, they were assumed to be susceptible to thermal embrittlement and required to be managed for reduction of fracture toughness. Radiation levels are significant enough that the components are susceptible to radiation embrittlement.

- Subsequently, for each potentially susceptible component, aging management under NUREG-1801, XI.M13 would be accomplished through either a supplemental examination of the affected component based on the neutron fluence to which the component has been exposed, as part of the applicant’s 10-year inservice inspection (ISI) program during the license renewal term, or a component-specific evaluation to determine its susceptibility to loss of fracture toughness. Flaws detected in CASS components are evaluated in accordance with the applicable procedures of IWB-3500. A flaw tolerance evaluation for components with ferrite content up to 25% is performed according to the principles associated with IWB-3640 procedures for submerged arc welds (SAW), disregarding the Code restriction of 20% ferrite in IWB-3641(b)(1).

The PINGP PWR Vessel Internals Program described in LRA Section B2.1.32 addresses the long term management of aging effects in the reactor vessel internals (RVI) components. The scope of the program includes the inspection plan and all related commitments and actions for monitoring, evaluation, and repair/replacement of components to manage the aging effects for reactor vessel internals components, thereby maintaining their ability to perform their intended function. The program consists of identifying the most susceptible or limiting components and developing appropriate inspection techniques. The program monitors the effects of aging degradation mechanisms on the intended function of reactor vessel internals components through one-time, periodic, and conditional examinations, and other aging management program elements, as needed, in accordance with the ASME Code, Section XI, and the guidelines established by the EPRI Materials Reliability Program (MRP) for PWR internals.

Preliminary License Renewal Commitment #25 commits to the following activities for managing the aging of reactor vessel internals components:

- Participate in the industry programs for investigating and managing aging effects on reactor internals
- Evaluate and implement the results of the industry programs as applicable to the reactor internals
- Upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.

The PWR Vessel Internals Program manages reduction of fracture toughness in reactor vessel internals components. Loss of fracture toughness is of consequence only if cracks exist. Cracking is expected to initiate at the surface and is detectable by augmented inspection. If the program identifies the BMI Column Cruciforms to be a susceptible or limiting component, then the program would develop appropriate inspection techniques. Currently, the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program conducts a visual VT-3 examination of the reactor vessel removable core support structures under Table IWB-2500-1, Examination Category B-N-3, once per Inservice Inspection interval.

The PINGP PWR Vessel Internals Program will include acceptance criteria established in the MRP guidelines. Any condition that is detected that does not satisfy the acceptance criteria must be evaluated. For ASME Code Section XI components the evaluation must be in accordance with ASME Code Section XI requirements. For non-ASME Code Section XI components, the recommendations provided in the MRP guidelines may be used.

The PINGP PWR Vessel Internals Program consists of identifying the most susceptible components and developing inspection techniques in the same way the NUREG-1801, XI.M13 Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program does. Implementation of the PWR Vessel Internals Program will provide reasonable assurance that aging effects will be managed such that components within the scope of this program will continue to perform their intended function(s) during the period of extended operation and is therefore an acceptable substitution for NUREG-1801, AMP XI.M13, “Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS).”

RAI 3.1.2-02

In the LRA 3.X.2 Tables, the applicant has assigned "Note E" to several line items for cast austenitic stainless steel components exposed to a treated water environment. The aging effect that requires management for these components is Cracking – SCC/Intergranular Attack (IGA). These components are: Piping/Fittings (Table 3.1.2-02), Pump Casings (Table 3.1.2-02), Valve Bodies (Table 3.1.2-02), Valve Bodies (Table 3.2.2-02), and Valve Bodies (Table 3.2.2-03). The GALL Report Table IV.C2, AMR item IV.C2-3 recommends monitoring and control of water chemistry in accordance with EPRI TR-105714 and material selection according to NUREG-0313, Rev 2, where reduced susceptibility to SCC is expected if carbon content is 0.035% or less and delta ferrite content is 7.5%. The GALL AMR states that if Cast Austenitic Stainless Steel (CASS) components do not meet either one of the two guidelines, then a plant specific program is to be evaluated that includes inspection methods to detect cracking and flaw evaluation of components susceptible to thermal embrittlement. The applicant credits the ASME Section XI ISI, IWB, IWC, and IWD program to manage cracking.

1) For these components, clarify whether PINGP controls water chemistry in accordance with the guidelines in EPRI Report No. TR-105714.
2) Clarify how the CASS components in these LRA AMR items meet the SCC susceptibility considerations of having less than an 0.035% carbon alloying content or less than a 0.75% delta ferrite content.
3) If it is determined that any of these CASS components do not meet the reduced susceptibility criteria on carbon and delta ferrite alloy contents, discuss the inspection methods that will be used to monitor for cracking in these components. Discuss the flaw evaluation methodologies used by PINGP to account for a change in the critical crack size used in the analysis as a result of a drop in the fracture toughness of the CASS components.
4) Ultrasonic testing (UT) methods may be incapable of detecting flaws in CASS components because of the dense, small grain-size microstructure of CASS, which results in significant, high amplitude UT background noise signals. If UT is proposed as the method for inspecting these components, provide your basis why the UT method selected would be capable of distinguishing between a UT signal that results from a flaw in the material as opposed to background UT signals that result from the CASS microstructure or abnormal geometries in the CASS component.

Clarify whether or not the inspection methods and flaw evaluation methods implemented for these components are within the scope of the PINGP ASME Section XI Inservice Inspection Program.

NSPM Response to RAI 3.1.2-02

Part 1

For the component types and AMR line items discussed in this RAI, PINGP credits the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and the Water Chemistry Program to manage cracking due to SCC/IGA of CASS components exposed to a treated water environment. For the subject components, the Water Chemistry Program controls water chemistry in accordance with Revision 5 of the "PWR Primary Water Chemistry Guidelines", EPRI TR-1002884, for primary and auxiliary water systems. EPRI TR-1002884 is a later revision of EPRI Report No. TR-105714.

Earlier revisions of the "PWR Primary Water Chemistry Guidelines", such as Revision 3, were numbered as EPRI TR-105714. Earlier revisions are cited in the GALL using the EPRI TR-105714 designator, with the exception of one reference to EPRI TR-1002884 contained in the reference list of Section XI.M2 of NUREG-1801. Though earlier revisions of both the primary and secondary water chemistry guidelines are cited in the GALL, the GALL also recognizes the use of later revisions. Therefore, use of later revisions is not considered an exception to NUREG-1801.

Part 2

The carbon alloying and delta ferrite content of the PINGP CASS reactor coolant components is either unknown or typically greater than the 0.035% carbon alloying content and the 7.5% delta ferrite which is discussed in NUREG-1801, Item No. IV.C2-3. However, NUREG-1801, Item No. IV.C2-3, allows an option for a plant-specific aging management program for CASS components that do not meet either of these guidelines. PINGP chose to use the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program for aging management in addition to the Water Chemistry Program.

Part 3

The PINGP ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program currently provides for volumetric examinations of reactor coolant piping and fittings in accordance with the Risk-Informed Inservice Inspection Program. ASME Section XI, Examination Category B-L-1 requires VT-1 visual examination of pressure retaining welds in pump casings. Examination Category B-L-2 requires VT-3 visual examination of pump casing internal surfaces, if disassembled. Examination Category B-M-2 requires VT-3 visual examination of internal surfaces of valve bodies, if disassembled. In addition, Examination Category B-P requires visual (VT-2) examination of all pressure retaining piping components. The PINGP ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is updated periodically as required by 10 CFR 50.55a, which is described further in the Response to RAI B2.1.3-1 in the NSPM letter dated December 18, 2008.

The PINGP Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program will identify the CASS piping components in the Reactor Coolant System potentially susceptible to thermal aging embrittlement and provide enhanced volumetric examinations on the base metal determined to be limiting due to applied stress, operating time, and environmental considerations using examination methods that meet the criteria of ASME Section XI, Appendix VIII. Alternatively, component-specific flaw tolerance evaluations will be performed using specific geometry and applied stress to demonstrate that the thermally-embrittled material has adequate toughness.

Flaws detected in CASS components will be evaluated in accordance with the applicable procedures of ASME Section XI, Subsections IWB-3500 or IWC-3500 under the PINGP ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. Alternatively, flaw tolerance evaluation for components with ferrite content up to 25% will be performed according to the principles associated with IWB-3640 procedures for submerged arc welds disregarding the Code restriction of 20% ferrite in IWB-3641(b)(1).

<u>Part 4</u>

The PINGP procedure for ultrasonic examination of cast stainless steel main coolant pipe welds is based on WCAP-11778, "Demonstration of Flaw Detection and Characterization Capabilities for Ultrasonic Examination of Main Coolant Loop Welds," March 1988, prepared by Westinghouse. The report describes the development of improved manual ultrasonic inspection techniques, and the optimization and qualification of manual ultrasonic flaw detection and characterization capabilities. The WCAP recognized that inspection of heavy-wall austenitic stainless steel components is difficult. The large grain sizes and the various levels of anisotropy lead to severe attenuation, wave velocity changes, and dispersive scattering of sound energy. These factors may result in mislocation of detected defects, specific volumes of material not being examined, and reflections from grain boundaries which may be interpreted as defects. However the ultrasonic testing is not impossible if measures are taken to avoid these factors which include knowledge of fabrication materials to be inspected, adequate surface preparation, knowledge of defects, sufficient training for inspection personnel, improved understanding of the sound beam propagation mechanism, appropriate selection of ultrasonic test equipment, and demonstration of the ultrasonic test procedures. PINGP ultrasonic examination procedures incorporate the research done by WCAP-11778 to improve the ultrasonic inspection of the cast austenitic stainless steel reactor coolant piping.

The PINGP procedure for ultrasonic examination of cast stainless steel main coolant pipe welds contains the following acceptance criteria to ensure the recording of any suspected flaws:

A. For straight beam examinations:

   1. All reflectors are to be recorded at the primary reference sensitivity.

2. All reflectors that equal or exceed 20% full screen height will be recorded in addition to any loss of back reflection greater than 50% that is not attributable to geometry.

B. For angle beam examinations the following are required:

1. All reflectors are to be recorded at the primary reference sensitivity.

2. All reflectors suspected to be a flaw shall be recorded regardless of amplitude or size.

3. All reflectors with amplitudes that exceed 20% distance amplitude correction (DAC) are to be evaluated to the extent that the operator can determine their shape, identity and location, source and cause to determine if they are valid or non-valid indications.

   - Valid indications are reflectors caused by flaws such as cracks, lack of penetration and embedded volumetric type discontinuities. For reactor coolant pipe longitudinal and circumferential welds, valid reflectors should appear distinct from material noise by an amplitude ratio of 2:1 with "travel" observed while scanning toward and away from the reflector. Such reflectors should have measurable length to be considered a recordable indication.

   - Non-valid indications include those due to material grain noise, beam redirection and mode conversion, weld or buttering interface and geometric reflectors.

4. All valid reflectors exceeding 20% DAC are to be evaluated and recorded to the extent that their shape, identity and location, can be determined for acceptance/rejection in accordance with ASME Section XI, IWB-3000.

5. All geometric reflectors, with amplitudes that exceed 20% DAC, are to be recorded (maximum amplitude, location, and what is causing reflector). The indications are to be evaluated to the extent that the operator can determine their shape, identity and location. For a reflector to be defined as geometric, the evaluation will be confirmed by the following:

   - Review of radiographs.

   - Review of weld joint design.

   - Previous examination results.

   - Perform cross sectional plot of the position of the indication by performing the following:

a. Obtain the OD weld profile (using contour gage) and the ID surface contour (using multiple thickness readings) to construct a cross sectional sketch at the maximum amplitude indication location.

b. Once the sketch of the component is constructed it will be utilized to plot the actual position of the reflector using the proper angle, transducer position and metal path.

Continuing investigations to improve the ultrasonic inspection of the cast austenitic stainless steel reactor coolant piping are focused on improving our knowledge of reactor coolant loop materials, specifically in the areas of material characterization and of their effect on ultrasonic beams. These investigations are ongoing in the industry and any improvements in the testing will be adopted by PINGP.

RAI 3.1.2-2-01

LRA Section: Table 3.1.2-2, page 3.1-70, page 3.1-71

Background: In LRA Table 3.1.2-2, on page 3.1-70, the AMR results for stainless steel valve bodies in a treated water environment show the aging effect of cracking managed by three AMPs: 1) ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program; 2) One-Time Inspection Program; and 3) Water Chemistry Program. The AMR result line for the Water Chemistry Program references three different GALL Report Volume 2 line items and three corresponding LRA Table 1 line items. The ASME Section XI, Subsections IWB, IWC, and IWD Program and the One-Time Inspection Program line items each reference one of the GALL Report Volume 2 line items and corresponding Table 1 line items.

Similarly, on page 3.1-71, the AMR results for stainless steel valve bodies in a treated water environment show aging effects of loss of material due to crevice or pitting corrosion managed by two AMPs: 1) One-Time Inspection Program; and 2) Water Chemistry Program. Again the line item for the Water Chemistry Program references multiple GALL Report Volume 2 and LRA Table 1 line items, but only one of the GALL Report Volume 2 line items is referenced by the Water Chemistry Program line item.

Issue: To compare AMR results in the LRA against recommended AMR results in the GALL Report, it is necessary to have a clear methodology to determine what AMP or combination of AMPs is proposed to manage the aging effect for each component, material, environment and aging effect (MEA) combination listed. However, the LRA provides no additional guidance on how an AMP line with multiple GALL Report Volume 2 line item references should be combined with companion AMP lines that refer to only one of those GALL Report line items, so that the AMP or AMPs proposed for each MEA combination is uniquely determined.

Request:

1) Provide additional guidance on how AMP lines referring to multiple GALL Report Volume 2 line items are to be combined with companion AMP lines to uniquely determine the AMP or combination of AMPs being proposed to manage the aging effect for a specific MEA combination.

2) Give specific examples of how this guidance is to be applied using the three AMR result lines at the bottom of LRA page 3.1-70 and the AMR result lines on LRA page 3.1-71.

NSPM Response to RAI 3.1.2-2-01

Part 1

The components in the Reactor Coolant System are primarily ASME Class I, reactor coolant pressure boundary components exposed to treated borated water and reference NUREG-1801 Chapter IV. However, the Reactor Coolant System also contains components which are not reactor coolant pressure boundary components and are exposed to either a treated borated water environment (NUREG-1801, Chapter V) or a demineralized water environment (NUREG-1801, Chap VIII). Therefore, in order to find appropriate aging management, PINGP utilized NUREG-1801 lines in other Chapters that included component/material/environment combinations which covered these components. To identify the different components, environments and the corresponding aging management programs applicable to the given component, the matched NUREG-1801 Volume 2 line items are to be combined. See the following examples.

Part 2

For the stainless steel RCS valve bodies shown on LRA Page 3.1-70 exposed to Treated Water (Int) and susceptible to cracking due to SCC/IGA: ASME Class 1 Reactor Coolant Pressure Boundary valves exposed to treated borated water are managed by ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD and Water Chemistry Programs in accordance with line item IV.C2-2. Valves exposed to demineralized water are managed by One-Time Inspection and Water Chemistry Programs in accordance with line Item VIII.E-30. Valves exposed to a treated borated water environment, but which are not reactor coolant pressure boundary components, are managed by the Water Chemistry Program in accordance with line Item V.D1-31.

For the stainless steel RCS valve bodies shown on LRA Page 3.1-71 exposed to Treated Water (Int) and susceptible to loss of material due to crevice or pitting corrosion: ASME Class 1 Reactor Coolant Pressure Boundary valves exposed to treated borated water are managed by the Water Chemistry Program in accordance with line item IV.C2-15. Valves exposed to demineralized water are managed by One-Time Inspection and Water Chemistry Programs in accordance with line Item VIII.E-29. Valves exposed to a treated borated water environment, but which are not reactor coolant pressure boundary components, are managed by the Water Chemistry Program in accordance with line Item V.D1-30.

RAI 3.1.2-5-01

LRA Section: Table 3.1.2-5, pages 3.1-128 and -129

Background: Table 3.1.2-5 (Steam Generator System) shows AMR results for nickel alloy U-tubes in a treated water environment with an aging effect of heat transfer degradation due to fouling. Note H is cited indicating that the aging effect is not included in the GALL Report for this component, material and environment combination. The recommended AMP is the Water Chemistry Program, alone.

Issue: The LRA does not provide any justification as to why the Water Chemistry Program, alone, is sufficient to provide management for this aging effect during the period of extended operation. Also, GALL Report Volume 2, line item V.A-16, which is for stainless steel heat exchanger tubes in a treated water environment, recommends use of Water Chemistry and One-Time Inspection to manage the aging effect of reduction of heat transfer due to fouling. Although the materials are different (nickel alloy vs stainless steel) the aging effect of reduction of heat transfer due to fouling would be expected to manifest itself in similar ways for both materials.

Request:

1) Provide an inspection activity to confirm effectiveness of the Water Chemistry Program to mitigate the aging effect of loss of heat transfer due to fouling in these components.

or

2) Provide a technical justification explaining why such a confirmation is not needed.

NSPM Response to RAI 3.1.2-5-01

<u>Part 1</u>

PINGP will provide an inspection activity to confirm effectiveness of the Water Chemistry Program to mitigate the aging effect of loss of heat transfer due to fouling in these components in a Treated Water (External) environment.

For the environment Treated Water (Ext), which is demineralized water, the LRA is being revised to add the One-Time Inspection Program to provide for the verification of the effectiveness of Water Chemistry to mitigate the aging effect of loss of heat transfer due to fouling in steam generator U-Tubes. The One-Time Inspection Program includes measures to verify the effectiveness of the Water Chemistry Program to mitigate aging effects including: (a) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience;

(b) identification of inspection locations in the system, component, or structure based on the aging effect; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect that is being examined; and (d) evaluation of the need for follow-up examination if degradation is identified that could jeopardize an intended function prior to the end of the period of extended operation.

Therefore, the following LRA revisions are made:

In LRA Table 3.1.2-5 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator System - Summary of Aging Management Evaluation, on page 3.1-128, in the line item for U-tubes (Unit 1) in a Treated Water (Ext) environment, for the Aging Effect Heat Transfer Degradation - Fouling, the One-Time Inspection Program is added, as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Line Item	Table 1	Notes
U-Tubes (Unit 1)	Heat Transfer	Nickel Alloy	Treated Water (Ext)	Heat Transfer Degradation - Fouling	Water Chemistry Program			H
					One-Time Inspection Program			H

In LRA Table 3.1.2-5 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator System - Summary of Aging Management Evaluation, on page 3.1-129, in the line item for U-tubes (Unit 2) in a Treated Water (Ext) environment, for the Aging Effect Heat Transfer Degradation - Fouling, the One-Time Inspection Program is added, as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Line Item	Table 1	Notes
U-Tubes (Unit 2)	Heat Transfer	Nickel Alloy	Treated Water (Ext)	Heat Transfer Degradation - Fouling	Water Chemistry Program			H
					One-Time Inspection Program			H

<u>Part 2</u>

An inspection activity to confirm effectiveness of the Water Chemistry Program to mitigate the aging effect of loss of heat transfer due to fouling in a Treated Water (Internal) environment is not required based on the following technical justification:

NUREG-1801, Volume 2, line item V.A-16, is for heat exchanger tubes exposed to treated water.

Per NUREG-1801, Section IX.D, Selected Definitions & Use of Terms for Describing and Standardizing – Environments, “Treated water is demineralized water, which is the base water for all clean systems. Depending on the system, this demineralized water may require additional processing. Treated water could be deaerated and include corrosion inhibitors, biocides, or some combination of these treatments. Unlike the PWR reactor coolant environment (treated borated water), the BWR reactor coolant environment (i.e., treated water) does not contain boron, a recognized corrosion inhibitor.”

The Treated Water (Internal) environment on the U-Tubes is reactor coolant and not demineralized water. As stated above boron is a recognized corrosion inhibitor. In accordance with NUREG-1800, Table 3.1-1, ID 81 and 83 (NUREG-1801 Line Items IV.D1-6 and IV.C2-15), the Water Chemistry Program alone is adequate for managing loss of material and cracking of nickel alloy exposed to reactor coolant.

In accordance with NUREG-1801, Section XI.M2, Water Chemistry, Element 4, Detection of Aging Effects, “This is a mitigation program and does not provide for detection of any aging effects. In certain cases as identified in the GALL Report, inspection of select components is to be undertaken to verify the effectiveness of the chemistry control program and to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period of operation.” NUREG-1801 Line Items IV.D1-6 and IV.C2-15 and Table 1, IDs 81 and 83, do not require verification of the effectiveness of the water chemistry control program in a reactor coolant environment.

NUREG-1801, Section IX.F, Selected Definitions & Use of Terms for Describing and Standardizing Aging Mechanisms, describes fouling as, “An accumulation of deposits. This term includes accumulation and growth of aquatic organisms on a submerged metal surface and also includes the accumulation of deposits, usually inorganic, on heat exchanger tubing. Biofouling, as a subset of fouling, can be caused by either macro-organisms (such as barnacles, Asian clams, zebra mussels, and others found in fresh and salt water) or micro-organisms, e.g., algae. Fouling can also be categorized as particulate fouling (sediment, silt, dust, and corrosion products), marine biofouling, or macrofouling, e.g., peeled coatings, debris, etc.” Fouling of the Steam Generator U-Tubes on the reactor coolant side would only occur through the buildup of corrosion products. Since NUREG-1800 and NUREG-1801 allow the use of the Water Chemistry Program alone for corrosion control in a reactor coolant environment, then a verification of the effectiveness of the Water Chemistry Program to mitigate the aging effect of loss of heat transfer due to fouling would not be required.

RAI 3.1.2.2.7-01

LRA Section: Section 3.1.2.2.7.1, page 3.1.12; Table 3.1.1, item 3.1.1-23, page 3.1-22; Table 3.1.2-4, pages 3.1-95 and -99.

Background: SRP-LR Section 3.1.2.2.7.1 states that cracking due to SCC could occur in the PWR stainless steel reactor vessel flange leak detection lines and the bottom mounted instrument guide tubes exposed to reactor coolant. GALL Report items IV.A.2-1 (bottom-mounted guide tube) and IV.A.2-5 (vessel flange leak detection line) recommend that a plant-specific AMP be evaluated. PINGP proposes to manage the aging effect of cracking due to SCC in these components with the Water Chemistry Program, alone.

Issue: SRP-LR provides acceptance criteria for plant-specific AMPs in Appendix A.1, Aging Management Review – Generic (Branch Technical Position RLSB-1), which is referenced in SRP-SR, Section 3.1.2.2.7.1.

Branch Technical Position RLSB-1 states that a plant-specific aging management program should include a "detection of aging effects" program element. PINGP's Water Chemistry Program is a mitigation program and does not include detection of aging effects. Therefore, PINGP's Water Chemistry Program, alone, does not meet the requirements for a plant-specific AMP under the criteria of Branch Technical Position RLSB-1.

Request:

1) Provide a plant-specific AMP or combination of existing AMPs that include a "detection of aging effect" program element for managing the aging effect of cracking due to SCC in the stainless steel reactor vessel flange leak detection line and in bottom mounted instrument guide tubes; and

2) Describe what examination techniques will be used to detect (or confirm the absence of) the aging effect of cracking due to SSC in the vessel flange leak detection line and the bottom mounted instrument guide tubes, or

3) Provide both a technical justification and a regulatory justification as to why confirmation of water chemistry effectiveness is not needed and why a "detection of aging effect" program element is not required.

NSPM Response to RAI 3.1.2.2.7-01

<u>Part 1</u>

The PINGP LRA is hereby revised to assign the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program to manage cracking due to SCC in addition to the Water Chemistry Program for the stainless steel Bottom Mounted Instrumentation (BMI) Guide Tubes & Fittings exposed to treated water. In addition, the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, and the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program are assigned to manage cracking due to SCC in addition to the Water Chemistry Program for the stainless steel Flange O-Ring Leak Detection Tubes.

Therefore, the following revisions are made to the LRA:

In LRA Table 3.1.1, Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Vessel, Internals, and Reactor Coolant System, on page 3.1-22, Line item 3.1.1-23 is revised to appear as follows:

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-23	Stainless steel reactor vessel closure head flange leak detection line and bottom-mounted instrument guide tubes	Cracking due to stress corrosion cracking	A plant-specific aging Management program is to be evaluated.	Yes, plant specific	The plant-specific AMPs that manage cracking due to stress corrosion cracking of the stainless steel reactor vessel closure head flange leak detection line are the Water Chemistry Program, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, and the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program. The plant-specific AMPs that manage cracking due to stress corrosion cracking of the stainless steel bottom-mounted instrument guide tubes are the Water Chemistry Program and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. Further evaluation is documented in Section 3.1.2.2.7.1.

In LRA Table 3.1.2-4, Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel System - Summary of Aging Management Evaluation, on page 3.1-95, the line item for Bottom Mounted Instrumentation (BMI) Guide Tubes & Fittings in Treated Water (Int), for the Aging Effect Cracking - SCC/IGA, is revised to add the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Line Item	Table 1	Notes
Bottom Mounted Instrumentation (BMI) Guide Tubes & Fittings	Pressure Boundary	Stainless Steel	Treated Water (Int)	Cracking - SCC/IGA	Water Chemistry Program	IV.A2-1	3.1.1-23	E
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program	IV.A2-1	3.1.1-23	E

In LRA Table 3.1.2-4, Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel System - Summary of Aging Management Evaluation, on page 3.1-99, the line item for Flange O-Ring Leak Detection Tubes in Treated Water (Int), for the Aging Effect Cracking - SCC/IGA, is revised to add the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Line Item	Table 1	Notes
Flange O-Ring Leak Detection Tubes	Pressure Boundary	Stainless Steel	Treated Water (Int)	Cracking - SCC/IGA	Water Chemistry Program	IV.A2-5	3.1.1-23	E
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program	IV.A2-5	3.1.1-23	E
					One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program	IV.A2-5	3.1.1-23	E

In LRA Section 3.1.2.2.7 on page 3.1-12, Part 1 is revised in its entirety to read as follows:

1. Cracking due to stress corrosion cracking could occur for the stainless steel reactor vessel closure head flange leak detection line. This aging effect is managed with the Water Chemistry Program, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, and the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program. Cracking due to stress corrosion cracking could occur for stainless steel reactor vessel bottom-mounted instrument guide tubes. This aging effect is managed with the Water Chemistry Program and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program.

   The Water Chemistry Program includes specifications for chemical species, sampling and analysis frequencies, and corrective actions for control of water chemistry. The program controls concentrations of known detrimental chemical species such as chlorides, fluorides, sulfates and dissolved oxygen below the levels known to cause degradation. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program includes periodic visual, surface, and/or volumetric examination of Class 1, 2, and 3 pressure-retaining components, their welded integral attachments, and bolting. Leakage tests are periodically performed on Class 1, 2, and 3 pressure-retaining components. The program also provides component repair and replacement requirements in accordance with ASME Section XI. The One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program inspects for the presence of cracking by performing one-time volumetric examinations on a sample of butt welds in Class 1 piping (including pipes, fittings, and branch connections) less than 4 inch nominal pipe size (NPS 4). The one-time inspections are performed at locations that are determined to be potentially susceptible to cracking. These programs assure the intended function of affected components will be maintained during the period of extended operation.

Part 2

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program manages cracking due to SCC for the Bottom Mounted Instrumentation (BMI) Guide Tubes & Fittings. The BMI Guide Tubes & Fittings receive a VT-2 visual inspection in accordance with ASME Section XI, Table IWB-2500-1, Examination Category B-P.

The One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program monitors for aging effects by performing one-time volumetric examinations of Class 1 small-bore piping to detect cracking at butt weld locations that are determined to be potentially susceptible to cracking using the methodology of the site specific NRC approved Risk Informed Inservice Inspection Program.

Part 3

Response not required.

RAI 3.2.2.2.3.6-01

LRA Section: Section 3.2.2.2.3.6, pages 3.2-7 and 3.2-8

Background: SRP-SR Section 3.2.2.2.3.6 states that loss of material due to pitting and crevice corrosion could occur for stainless steel piping, piping components, piping elements, and tanks exposed to internal condensation. LRA Section 3.2.2.2.3.6 and Table 3.2.1, item 3.2.1-08, both state that the AMR result in the GALL Report is not applicable because PINGP does not have stainless steel piping and piping components exposed to condensation in GALL Report Chapter V [engineered safety features] systems.

Issue: The statement in LRA Section 3.2.2.2.3.6 does not address stainless steel tanks, which are included in the list of components that may be in an environment of internal condensation in SRP-SR Section 3.2.2.2.3.6. Also, it is not clear how PINGP determined that stainless steel piping in the containment spray is not exposed to internal condensation.

Request:

1) Provide the basis for the statement in the LRA that there are no stainless steel piping and piping components exposed to condensation in GALL Report Chapter V systems, specifically addressing stainless steel piping in the containment spray system (GALL Report Volume 2, item V.A-26) and stainless steel tanks in the safety injection system (GALL Report Volume 2, item V.D1-29).

NSPM Response to RAI 3.2.2.2.3.6-01

The Containment Spray System spray nozzles and selected piping were assigned an internal environment of Primary Containment Air (Int). These components are completely within the Auxiliary Building and Containment. The Auxiliary Building indoor areas are protected from weather and have an ambient temperature range between 60^{o}F to 125^{o}F. The Containment indoor areas are protected from weather and have an ambient temperature range between 50^{o}F and 120^{o}F. The internal air/gas environment of the Containment Spray System piping and nozzles is at the same temperature as the surrounding room temperature such that condensation is not expected.

The partially filled stainless steel tanks in the Safety Injection System are the Refueling Water Storage Tanks and the Reactor Coolant Safety Injection Accumulators. These tanks are completely contained within the Auxiliary Building and Containment respectively. The Auxiliary Building indoor areas are protected from weather and have an ambient temperature range between 60^{o}F to 125^{o}F. The Containment indoor areas are protected from weather and have an ambient temperature range between 50^{o}F and 120^{o}F. The internal fluid environment and internal air/gas environment of these tanks are at the same temperature as the surrounding room temperature such that condensation is not expected. If a portion of a component was exposed to fluid, then typically the component was conservatively assumed to be fully exposed to the fluid environment for performing the Aging Management Evaluations.

The PINGP Systems in GALL Chapter V were shown to have internal environments of Lubricating Oil (Int), Nitrogen Gas (Int), Plant Indoor Air - Uncontrolled (Int), Primary Containment Air (Int), and Treated Water (Int). The internal environment of “condensation” was not utilized and consequently LRA Section 3.2.2.2.3.6 and Table 3.2.1, item 3.2.1-08, are both correct in stating that the AMR result in the GALL Report is not applicable.

RAI 3.2.2.2.4.2-01

LRA Section: Section 3.2.2.2.4.2, page 3.2-8; Table 3.2.1, item 3.2.1-10, page 3.2.13.

Background: The SRP-LR in Section 3.2.2.2.4.2 states that reduction in heat transfer due to fouling could occur for stainless steel heat exchanger tubes exposed to treated water and recommends that effectiveness of water chemistry control to mitigate this aging effect should be confirmed to ensure that reduction of heat transfer is not occurring and that the component's intended function will be maintained during the period of extended operation.

Issue: The AMR results presented in the LRA state that the Water Chemistry Program, alone, is adequate to control this aging effect and that verification of Water Chemistry Program effectiveness is not needed. The discussions in LRA Section 3.2.2.2.4.2 and item 3.2.1-10 refer to GALL Report line items 3.2.1-48 and 3.2.1-49 where the Water Chemistry Program, alone, is recommended to manage the aging effects of cracking due to SCC and loss of material due to pitting and crevice corrosion for stainless steel piping and piping components in a borated treated water environment.

Request:

1) Identify the heat exchangers in the engineered safety features system that are the subject of this AMR.
2) State whether these heat exchangers are periodically examined under an existing plant program to the extent that indications of fouling in the heat exchanger tubes can be detected.
3) Explain why reference to AMR results where the aging effects are cracking and loss of material are used to support not monitoring for the aging effect of reduction in heat transfer due to fouling.
4) Provide a technical justification for not performing a one-time inspection to confirm Water Chemistry Program Effectiveness, as recommended in the GALL Report for this component, material, environment and aging effect combination.

NSPM Response to RAI 3.2.2.2.4.2-01

Part 1

The heat exchangers in the engineered safety features system that are the subject of this AMR are as follows:

Reactor Coolant Pump Thermal Barrier Heat Exchanger
Containment Spray Pump Seal Cooler Tubing
Residual Heat Removal Heat Exchanger Tubing
Residual Heat Removal Pump Seal Water Cooler Tubing
Safety Injection Pump Seal Water Cooler Tubing

Part 2

There are no requirements to examine these heat exchangers.

Parts 3 & 4

SRP Subsection 3.2.2.2.4.2, Table 3.2-1, ID 10, EP-34 (NUREG-1801, Volume 2, line item V.A-16) is for stainless steel heat exchanger tubes exposed to treated water.

Per NUREG-1801, Section IX.D, Selected Definitions & Use of Terms for Describing and Standardizing – Environments: “Treated water is demineralized water, which is the base water for all clean systems. Depending on the system, this demineralized water may require additional processing. Treated water could be deaerated and include corrosion inhibitors, biocides, or some combination of these treatments. Unlike the PWR reactor coolant environment (treated borated water), the BWR reactor coolant environment (i.e., treated water) does not contain boron, a recognized corrosion inhibitor.”

The Treated Water (Int) environment in the heat exchanger tubes is treated borated water and not demineralized water. As stated above boron is a recognized corrosion inhibitor. In accordance with NUREG-1800, Table 3.2-1, IDs 48 and 49, (NUREG-1801 Line Items V.A-28, V.D1-31, V.A-27, and V.D1-30), the Water Chemistry Program alone is adequate for managing loss of material and cracking of stainless steel exposed to treated borated water.

In accordance with NUREG-1801, XI.M2 Water Chemistry, Element 4, Detection of Aging Effects, “This is a mitigation program and does not provide for detection of any aging effects. In certain cases as identified in the GALL Report, inspection of select components is to be undertaken to verify the effectiveness of the chemistry control program and to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period of operation.” NUREG-1801 Line Items V.A-28, V.D1-31, V.A-27, and V.D1-30 and NUREG-1801, Table 2, IDs 48 and 49 do not require verification of the effectiveness of the water chemistry control program.

NUREG-1801, Section IX.F, Selected Definitions & Use of Terms for Describing and Standardizing Aging Mechanisms, describes fouling as “An accumulation of deposits. This term includes accumulation and growth of aquatic organisms on a submerged metal surface and also includes the accumulation of deposits, usually inorganic, on heat exchanger tubing. Biofouling, as a subset of fouling, can be caused by either macro-organisms (such as barnacles, Asian clams, zebra mussels, and others found in fresh and salt water) or micro-organisms, e.g., algae. Fouling can also be categorized as particulate fouling (sediment, silt, dust, and corrosion products), marine biofouling, or macrofouling, e.g., peeled coatings, debris, etc.” Fouling of the heat exchanger tubes on the treated borated water side would only occur through the buildup of corrosion products. Since NUREG-1800 and NUREG-1801 allow the use of the Water Chemistry Program alone for corrosion control in treated borated water environment, then a verification of the effectiveness of the Water Chemistry Program to mitigate the aging effect of reduction of heat transfer due to fouling would not be required. In addition, NUREG-1801 does not include reduction in heat transfer due to fouling as an applicable aging effect in a treated borated water environment.

Enclosure 1
NSPM Responses to NRC Requests for Additional Information
Dated December 18, 2008

RAI 3.3.1-51-01

LRA Section: Table 3.3.1, item number 3.3.1-51, page 3.3-54; Table 3.3.2-3; Table 3.3.2-5; Table 3.3.2-8; Table 3.3.2-9; Table 3.3.2-11; Table 3.3.2-13; Table 3.3.2-20

Background: The GALL Report indicates that the aging effect/mechanism for this Table 3.3.1, item number 3.3.1-51 is loss of material due to pitting, crevice and galvanic corrosion. The component is copper alloy piping, piping components, piping elements and heat exchanger elements exposed to closed cycle cooling water, and galvanic corrosion is normally an aging mechanism associated with copper or copper alloy components.

Issue: Review of the AMR result lines in the 3.X.2 tables that refer to item number 3.3.1-51 did not find any AMR results that list galvanic corrosion as an aging mechanism.

Request:

1) Why is the aging mechanism of galvanic corrosion not included for these copper alloy components?

NSPM Response to RAI 3.3.1-51-01

Analysis tools provided by Electric Power Research Institute (EPRI) reports, Westinghouse generic topical reports and other industry guidelines were the primary means to identify and evaluate aging effects. Operating experience, both industry and plant-specific, was also used to identify aging effects. The GALL report was used to identify aging management programs which were determined by the NRC to be acceptable programs to manage the identified aging effects.

Copper and Copper Alloys are in the middle of the galvanic series and will preferentially corrode when coupled with more cathodic metals (such as stainless steel). However, the rate of corrosion is expected to be low due to the small electrochemical potential difference. Operating experience at PINGP has not identified galvanic corrosion concerns with Copper and Copper Alloys. Therefore galvanic corrosion was not considered applicable to Copper and Copper alloys.

RAI 3.3.1-76-01

LRA Section: Table 3.3.1, item number 3.3.1-76, page 3.3-60; and various lines referring to 3.3.1-76 in Table 3.3.2-3, Table 3.3.2-5, Table 3.3.2-6, Table 3.3.2-7, Table 3.3.2-8, Table 3.3.2-20, Table 3.3.2-21

Background: The discussion column in LRA item number 3.3.1-76 states that the AMR results are consistent with the GALL Report and that the aging effect is managed by the Open-Cycle Cooling Water System Program. Review of the 3.X.2 tables listed above finds multiple AMR result lines referring to item number 3.3.1-76 where the AMP is the

Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program and generic note E is cited, indicating that the line is consistent with the GALL Report for component, material, environment combination, but a different AMP is used.

Issue: The statement in the discussion column says the aging effect is managed by the Open-Cycle Cooling Water System Program. This is either incorrect or misleading since the Open-Cycle Cooling Water System Program is used to manage the aging effect for only some of the AMR result lines, and the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is used to manage the aging effect in other ARM result lines.

Request:

1) Explain why the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, rather than the Open-Cycle Cooling Water System Program, is used for some of the AMR result lines.

2) Revise the discussion in LRA Table 3.3.1, item 3.3.1-76, to clarify that two different aging management programs are used, or justify why the LRA does not need to be revised.

NSPM Response to RAI 3.3.1-76-01

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is used in lieu of the Open-Cycle Cooling Water System Program where the components managed are not exposed to an Open-Cycle Cooling Water environment. For LRA Table 3.3.1, line item 3.3.1-76, the Internal Surfaces in Miscellaneous Piping and Ducting Components Program is credited for managing aging effects for components exposed to waste water or potable water environments in the Control Room and Miscellaneous Area Ventilation (Table 3.3.2-5), Cooling Water (Table 3.3.2-6), Diesel Generator and Screen house Ventilation (Table 3.3.2-7), Diesel Generator and Support (Table 3.3.2-8), Waste Disposal (Table 3.3.2-20) and Water Treatment (Table 3.3.2-21) Systems. The Component Cooling Water System (Table 3.3.2-3) does not reference line item 3.3.1-76.

In LRA Table 3.3.1, line item number 3.3.1-76, the discussion column should also reference the Internal Surfaces in Miscellaneous Piping and Ducting Components Program. Accordingly, the discussion column entry for LRA Table 3.3.1, line item number 3.3.1-76 on page 3.3-60, is revised to read:

> "Consistent with NUREG-1801. This aging effect is managed with the Open-Cycle Cooling Water System Program. In some cases, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is credited in lieu of the Open-Cycle Cooling Water System Program."

RAI 3.3.1-77-01

LRA Section: Table 3.3.1, item number 3.3.1-76, page 3.3-60; and various lines referring to 3.3.1-77 in Table 3.3.2-3, Table 3.3.2-5, Table 3.3.2-6, Table 3.3.2-8, Table 3.3.2-17, and Table 3.3.2-20

Background: The discussion column in LRA item number 3.3.1-77 states that the AMR results are consistent with the GALL Report and that the aging effect is managed by the Open-Cycle Cooling Water System Program. It also states that in some cases, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program or the Fire water System Program is credited in lieu of the Open-Cycle Cooling Water System Program. Review of the 3.X.2 tables listed above finds multiple AMR result lines referring to item number 3.3.1-77. However, none of these AMR result lines identify the Fire Water System Program as the AMP credited to manage the aging effect in these components.

Issue: The statement in the discussion column says in some instances the Fire Water System Program is credited in lieu of the Open-Cycle Cooling Water System Program appears to be incorrect.

Request:

1) Identify the location in the LRA of AMR result lines that refer to item number 3.3.1-77 where the Fire Water System Program is credited to provide aging management, or correct the description in the discussion column for LRA Table 3.3.1, item number 3.3.1-77, saying that the Fire Water System Program is credited.
2) Explain why the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program or the Fire water System Program (if actually used) are credited in lieu of the Open-Cycle Cooling Water System Program for some of these AMR result lines.

NSPM Response to RAI 3.3.1-77-01

In LRA Table 3.3.1, on page 3.3-60, line item number 3.3.1-77, reference to the Fire Water System Program for providing aging management is incorrect. The reference to the Fire Water System should be deleted. Accordingly, the discussion column entry for LRA Table 3.3.1, line item number 3.3.1-77 is revised to read:

> "Consistent with NUREG-1801. This aging effect is managed with the Open-Cycle Cooling Water System Program. In some cases, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is credited in lieu of the Open-Cycle Cooling Water System Program."

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is used in lieu of the Open-Cycle Cooling Water System Program where the components managed are not exposed to an Open-Cycle Cooling Water environment.

For LRA Table 3.3.1, line item 3.3.1-77, the Internal Surfaces in Miscellaneous Piping and Ducting Components Program is credited for managing aging effects for components exposed to a waste water environment in the Waste Disposal System (Table 3.3.2-20).

RAI 3.3.1-78-01

LRA Section: Table 3.3.1, item number 3.3.1-78, page 3.3-60

Background: The discussion column in LRA item number 3.3.1-78 states that this line was not used at PINGP and says, "See LRA line item 3.3.1-79 for further discussion."

Issue: It does appear that the AMR results for LRA item number 3.3.1-78 could be included as a subset of the AMR results in LRA item number 3.3.1-79 based on similarity of component, material, environment and aging effect. However, there is no mention of LRA line item 3.3.1-78 in the discussion column of LRA line item 3.3.1-79.

Request:

1) Revise the statement in LRA item number 3.3.1-78, or add an appropriate discussion of 3.3.1-78 into the discussion column of LRA item number 3.3.1-79

NSPM Response to RAI 3.3.1-78-01

In LRA Table 3.3.1, the discussion column in LRA Item number 3.3.1-78 is intended to provide a convenient link to clarify that the material, environment, aging effect combination in line 3.3.1-78 is applicable to PINGP although it is evaluated under a different line. Line 3.3.1-78 is not intended to be included by reference in line 3.3.1-79. Line 3.3.1-78 is not used at PINGP, and no additional detail is required in line 3.3.1-79 discussion column.

RAI 3.3.2-08-01

In LRA Tables 3.3.2-08, 3.3.2-09, 3.4.2-03, 3.4.2-04, flex connections and expansion joints that are fabricated from rubber and natural rubber, exposed to an internal environment of treated or raw water and subject to the aging effects of change in material properties and cracking referenced the applicable plant-specific note 323 or 423 which states in part, that the external environment is the same as the internal environment. Please clarify if the internal environment for these AMR line items is identical to the external environment or if the external environment is more aggressive. If the latter is the case, identify the external environment for these components. Please consider in your response the impact RAI B2.1.14 may have, and if the appropriate program to manage the effects of aging for non-metallic components will be capable of being credited so that the external surface may be representative of the internal surfaces. If not, provide an appropriate program that is capable of managing the aging of the internal surfaces for non-metallic components.

NSPM Response to RAI 3.3.2-08-01

Notes 323 and 423 state, "The External Surfaces Monitoring Program is credited with managing aging effects of internal surfaces where the external surfaces are subject to the same environment or stressor as the internal surfaces such that the external condition is representative of the internal condition." The external environment (Plant Indoor Air – Uncontrolled) for these line items is not identical to the internal environment (Raw Water or Treated Water); however the external thermal exposure stressor (i.e., temperature), which may result in cracking and change in material properties, is the same as the internal thermal exposure stressor (i.e., temperature). In addition, the external environment, Plant Indoor Air – Uncontrolled, is more aggressive related to the same aging effects, cracking and change in material properties, due to the additional aging mechanisms of ultraviolet exposure and ozone exposure. Therefore, the external surface condition is representative of the internal surface condition and the External Surfaces Monitoring Program is credited with detection of the aging effects on the external surfaces prior to aging effects on the internal surfaces resulting in a loss of intended function. The External Surfaces Monitoring Program described in Section B2.1.14 of the LRA is an appropriate program for managing aging of these non-metallic components. For additional discussion, see the response to RAI AMP-B2.1.14-1 in NSPM letter dated December 5, 2008.

RAI 3.3.2-9-01

LRA Section: Table 3.3.2-9, page 3.3-206

Background: LRA Table 3.3.2-9 shows AMR results for copper alloy piping/fittings in the fire protection system in a fuel oil environment with an aging effect of cracking due to SCC/IGA. Three AMPs are shown as applicable for these components: 1) Fire Protection Program; 2) Fuel Oil Chemistry Program; and 3) One-Time Inspection Program. Note H is used for these AMR result lines, and there is no reference to GALL Report Volume 2 line items.

Issue: Because these results are not in the GALL Report, there are no GALL Report Volume 2 line item references to link the three AMPs. Consequently, there is no way for a reviewer to determine whether the aging effect is managed by all three of the AMPs together, or whether for some components it is managed by a combination of only two programs. For example, the Fuel Oil Chemistry Program and the One-Time Inspection Program might be credited for some components; while for other components the Fire Protection Program and the One-Time Inspection Program might be credited; and for still other components the Fuel Oil Chemistry Program and the Fire Protection Program might be credited.

Request:

1) For all components in these AMR result lines, is the aging effect managed by all three AMPs together?

2) If all components in these AMR result lines are not managed by all three AMPs together, then identify what combinations of AMPs are used, and for what set of components each combination of AMPs is credited.

3) Is Fuel Oil Chemistry Program credited for all components in these AMR results lines?

4) Are there any components for which Fuel Oil Chemistry Program, alone, is credited?

5) For components where the Fire Protection Program is credited, is the Fire Protection Program credited to provide both mitigation and detection of the aging effect? If credited to provide detection of the aging effect, then explain how the Fire Protection Program detects the aging effect of cracking due to SCC/IGA.

NSPM Response to RAI 3.3.2-9-01

<u>Parts 1 & 2</u>

For all copper alloy piping/fitting components addressed in these Aging Management Review line items, the aging effect of cracking due to SCC/IGA is managed by a combination of all three Aging Management Programs: Fire Protection Program, Fuel Oil Chemistry Program, and One-Time Inspection Program.

<u>Parts 3 & 4</u>

For all copper alloy piping/fitting components addressed in these Aging Management Review line items, the aging effect of cracking due to SCC/IGA is managed by a combination of all three Aging Management Programs: Fire Protection Program, Fuel Oil Chemistry Program, and One-Time Inspection Program.

<u>Part 5</u>

The Fire Protection Program does not provide for mitigation of the aging effect but is credited with providing detection of the aging effect. The combination of aging management activities performed in accordance with the requirements of the Fire Protection, Fuel Oil Chemistry, and One-Time Inspection Programs provide reasonable assurance that cracking of the diesel-driven fire pump fuel supply line will be adequately managed for the period of extended operation. For additional discussion, see the response to RAI AMP-B2.1.15-1 in NSPM letter dated December 5, 2008.

RAI 3.3.2-13-01

LRA Section: Table 3.3.2-13, pages 3.3-259, -263, -265, -266, and -269.

Background: On the pages listed above, there are AMR result lines for various carbon steel piping components in a treated water environment where the aging effect is identified as cracking due to stress corrosion cracking and the AMP proposed to manage the aging effect is the Closed-Cycle Cooling Water Program, alone. These AMR result lines cite generic note H, (Aging effect not in NUREG-1801 for this component, material, and environment combination not applicable.)

Issue: Cracking due to SCC is not normally associated with carbon steel components. In addition, the Closed-Cycle Cooling Water System Program (B2.1.9) does not include any examination techniques applicable for carbon steel components that are capable of detecting cracks due to SCC. However, the "detection of aging effects" program element for GALL AMP XI.M21, Closed-Cycle Cooling Water System, states that inspection and testing should assure the detection of corrosion or SCC before the loss of intended function.

Request:

1) What is the basis for expecting that cracks due to SCC may occur in the carbon steel piping components (pipe, valves, pumps, tanks, heat exchanger components) exposed to treated water in the plant sample system? Cite any plant-specific or industry operating experience or information that supports occurrence of this aging effect in carbon steel piping components.
2) Provide an examination technique for these components that is capable of detecting cracks due to SCC, or provide a justification as to why examination for cracks is not needed to ensure adequate aging management for these components.

NSPM Response to RAI 3.3.2-13-01

Part 1

The PINGP operating experience review for the Plant Sample System identified microbiological bacteria in the Cold Lab Sample Chiller. On a routine quarterly sample of the Cold Lab Sample Chiller, aerobic bacteria counts showed 10,000 bact/ml. This was confirmed by a backup sample. This was the third time in a year that bacteria counts were elevated. On each occasion additions of biocide were made, and the bacteria would become evident again after a few months. On the final occasion the nitrites in the corrosion inhibitor were totally consumed. On Sept. 7, 2001, the Cold Lab Sample Chiller was drained, flushed, and refilled with an approximately 50/50 mix of Fleet-charge Antifreeze which also contains a nitrite-based corrosion inhibitor.

In accordance with EPRI 1010639, Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 4, Final Report, January 2006, stress corrosion cracking (SCC) of carbon and low-alloy steels is considered an applicable aging mechanism in treated water systems in which a nitrite corrosion inhibitor is used, there is a potential for MIC contamination, pH is less than 10.5, and temperature is less than 210°F. Due to this plant specific operating experience, cracking due to SCC was assumed in the Plant Sample System hot and cold lab sample chiller components made of carbon steel.

Part 2

The Closed-Cycle Cooling Water System Program is both a preventive and condition monitoring program that is based on the Electric Power Research Institute (EPRI) "Closed Cooling Water Chemistry Guideline", TR-107396, Revision 1. The program includes preventive measures to minimize corrosion, heat transfer degradation, and stress corrosion cracking (SCC); and testing and inspection to monitor the effects of corrosion, heat transfer degradation, and SCC on the intended functions of the components. The preventive measures consist of maintaining the system corrosion inhibitor concentrations within the specified limits by periodic testing. Testing is performed to verify key chemistry parameters and to measure impurities, conductivity and microbiological growth. Inspections are performed to identify corrosion, fouling and SCC that may be present.

Periodic visual inspections, performed in conjunction with scheduled maintenance activities, are sufficient to detect loss of material due to corrosion and heat transfer degradation due to fouling. Inspections for stress corrosion cracking will be performed by visual examination with a magnified resolution (i.e., enhanced visual) as described in 10 CFR 50.55a(b)(2)(xxi)(A) or with ultrasonic methods.

In response to this RAI, and to clarify the scope of Closed Cycle Cooling Water system inspections, the program enhancement described in Section B2.1.9 of the PINGP LRA is revised as follows.

In LRA Section B2.1.9 on page B-28, delete the existing enhancement and replace it in its entirety with the following:

- Monitoring and Trending

  The program will be enhanced to include periodic inspection of accessible surfaces of components serviced by closed-cycle cooling water when the systems or components are opened during scheduled maintenance or surveillance activities. Inspections are performed to identify the presence of aging effects and to confirm the effectiveness of the chemistry controls. Visual inspection of component internals will be used to detect loss of material and heat transfer degradation. Enhanced visual or volumetric examination techniques will be used to detect cracking.

To reflect this change, Preliminary License Renewal Commitment No. 6 included in the LRA transmittal letter dated April 11, 2008, is revised to read as follows:

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
6	The Closed-Cycle Cooling Water System Program will be enhanced to include periodic inspection of accessible surfaces of components serviced by closed-cycle cooling water when the systems or components are opened during scheduled maintenance or surveillance activities. Inspections are performed to identify the presence of aging effects and to confirm the effectiveness of the chemistry controls. Visual inspection of component internals will be used to detect loss of material and heat transfer degradation. Enhanced visual or volumetric examination techniques will be used to detect cracking.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.9

RAI 3.3.2-20-01

In LRA Table 3.3.2-20, several AMR Line Items reference the following:

- Table 1 item 3.3.1-77 and GALL Report Volume 2 line item VII.C1-5
- Table 1 item 3.4.1-33 and GALL Report Volume 2 line item VIII.E-3
- Table 1 item 3.3.1-82 and GALL Report Volume 2 line item VII.C1-3

These AMR line items credit the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The staff noted that the environment for some of these line items as described above is raw water on the external surface. Please clarify how a visual inspection of the internal surfaces of the heat exchanger components and/or tubes will be capable of determining the condition of the surfaces exposed to the raw water on the external surface of these heat exchanger components and/or tubes.

NSPM Response to RAI 3.3.2-20-01

The components which credit the Internal Surfaces and Miscellaneous Piping and Ducting Components Program for a raw water external environment are heat exchanger tubes and tubesheets (heat exchanger components). Internal and external environments are assigned to heat exchanger tubes and tubesheets to evaluate the environment to which each side is exposed. The external sides of heat exchanger tubes and tubesheets are physically internal to the heat exchangers, and therefore the Internal Surfaces and Miscellaneous Piping and Ducting Components Program is appropriate for management of aging effects. The internal environments, which are also internal to the heat exchangers, are evaluated under separate lines.

RAI 3.3.2-20-02

In LRA Table 3.3.2-20 and 3.4.2-08, several AMR line items reference the following:

- Table 1 item 3.3.1-77 and GALL Report Volume 2 line item VII.C1-5
- Table 1 item 3.4.1-33 and GALL Report Volume 2 line item VIII.E-3
- Table 1 item 3.4.1-8 and GALL Report Volume 2 line item VIII.G-36
- Table 1 item 3.4.1-32 and GALL Report Volume 2 line item VIII.A-4

These AMR line items credit the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, which performs a periodic visual inspection of the components. Please justify how a visual inspection alone, is capable of detecting the aging effect of loss of material in heat exchanger components and tubes in those regions that are not directly visible (e.x. the bend of a heat exchanger tube) or provide an appropriate inspection technique or program that will be capable of detecting the aging effect of loss of material for those regions that are not directly accessible for a visual inspection.

NSPM Response to RAI 3.3.2-20-02

In LRA Table 3.3.2-20, on pages 3.3-311 through 3.3-315, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is credited for managing Loss of Material in heat exchanger components and tubes. These line items consist of heat exchanger shells, tubesheets, channelheads and tubes. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program performs visual inspections of internal surfaces of mechanical components during scheduled preventive and corrective maintenance activities, or during other routinely scheduled tasks such as surveillance procedures, when internal surfaces are made accessible for inspections. Inspection locations will be chosen to include conditions susceptible to the aging effects of concern. Visual inspections are expected to detect the presence of corrosion and cracking of accessible internal surfaces of metallic components. Aging effects will be detected through the presence of indications such as rust, discoloration, scale/deposits, pitting, and surface discontinuities. Implementation of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program provides a reasonable assurance that aging effects will be managed such that the heat exchanger components will continue to perform their intended function(s) during the period of extended operation.

In LRA Table 3.4.2-8, on pages 3.4-126 and 3.4-127, and on page 3.4-131, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is credited for managing Loss of Material in heat exchanger components and tubes. These heat exchanger components and tubes are supplied by the Cooling Water System and should not have credited the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program for aging management. The appropriate aging management program is the Open-Cycle Cooling Water System

Program. The Open-Cycle Cooling Water System Program conducts eddy current testing of these heat exchanger tubes to detect loss of material.

Therefore, the following changes are made to Table 3.4.2-8 of the LRA:

In Table 3.4.2-8 on pages 3.4-126 and -127, for Heat Exchanger Components exposed to Raw Water (Int), the lines aligned to Table 1, Item 3.4.1-08, are hereby deleted. The remaining lines for this component, material and environment combination appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Line Item	Table1 Item	Notes
Heat Exchanger Components	Pressure Boundary	Carbon Steel	Raw Water (Int)	Loss of Material - Crevice Corrosion	Open-Cycle Cooling Water System Program	VIII.E-6	3.4.1-31	A
				Loss of Material - Fouling	Open-Cycle Cooling Water System Program	VIII.E-6	3.4.1-31	A
				Loss of Material - Galvanic Corrosion	Open-Cycle Cooling Water System Program	VIII.E-6	3.4.1-31	A
				Loss of Material - General Corrosion	Open-Cycle Cooling Water System Program	VIII.E-6	3.4.1-31	A
				Loss of Material - MIC	Open-Cycle Cooling Water System Program	VIII.E-6	3.4.1-31	A
				Loss of Material - Pitting Corrosion	Open-Cycle Cooling Water System Program	VIII.E-6	3.4.1-31	A

In Table 3.4.2-8 on page 3.4-131, for Heat Exchanger Tubes exposed to Raw Water (Int), the four lines aligned to Table 1 Item 3.4.1-32 are hereby deleted and replaced with the following:

Component Type	Intended Function	Material	Environment	Aging Effect requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Line Item	Table1 Item	Notes
Heat Exchanger Tubes	Pressure Boundary	Copper-Nickel	Raw Water (Int)	Loss of Material - Crevice Corrosion	Open-Cycle Cooling Water System Program	VII.C1-3	3.3.1-82	A
				Loss of Material - Fouling	Open-Cycle Cooling Water System Program	VII.C1-3	3.3.1-82	A
				Loss of Material - MIC	Open-Cycle Cooling Water System Program	VII.C1-3	3.3.1-82	A
				Loss of Material - Pitting Corrosion	Open-Cycle Cooling Water System Program	VII.C1-3	3.3.1-82	A

RAI 3.3.2.2.4.1-01

LRA Section: Section 3.3.2.2.4.1, page 3.3-34; Table 3.3.1, item number 3.3.1-7, page 3.3-45.

Background: SRP-LR Section 3.3.2.2.4.1 recommends the Water Chemistry program and a plant-specific verification activity to manage the aging effect of cracking due to SSC and cyclic loading in PWR non-regenerative heat exchanger components exposed to treated borated water. The SRP-LR states that an acceptable verification program is to include temperature and radioactivity monitoring of the shell side water, and eddy current testing of the tubes.

Issue: PINGP proposes to manage the aging effect in this component with the Water Chemistry Program and the One-Time Inspection Program. PINGP cites NUREG-1785, Safety Evaluation Report Related to License Renewal of H.B. Robinson Steam Electric Plant, Unit 2, as providing a precedent for use of the One-Time Inspection Program. However, there is insufficient information in the LRA to determine whether the One-Time Inspection program is adequate to perform verification for this aging effect in these components.

Request:

1) Provide a description of the examination methodology to be used to verify effectiveness of the Water Chemistry Program to mitigate the aging effect of cracking due to SCC and cyclic loading in the components that are included in this AMR result line. Also discuss if the methodology is adequate to detect the aging effect of cracking in these components.
2) Will eddy current testing of the tubes be included in the One-Time Inspection Program? If not, then how will potential cracking in the tubes be detected or confirmed not to have occurred?
3) Are there any installed instruments that provide measurements of temperature and radioactivity on the shell side of the heat exchanger?
4) What has been the operating experience with these components? Have there been any failures due to cracking or any other adverse operating experience?
5) Has eddy current testing of the heat exchanger tubes previously been performed? If so, have results indicated evidence of cracking?
6) Address the One-Time Inspections for both LRA line item 3.3.1-7 (non-regenerative heat exchanger components) and 3.3.1-8 (regenerative heat exchanger components) in your response to this RAI.

NSPM Response to RAI 3.3.2.2.4.1-01

Part 1

The purpose of the PINGP Water Chemistry Program is to periodically monitor water chemistry and control detrimental contaminants (such as chlorides, fluorides, dissolved oxygen, and sulfate) to levels below those known to result in cracking. The One-Time Inspection Program provides assurance, through sampling inspections using nondestructive examination techniques, that aging is not occurring, or that the rate of degradation is so insignificant that additional aging management actions are not warranted.

The One-Time Inspection Program, in general, relies upon established nondestructive examination techniques of the PINGP ASME Section XI Inservice Inspection Program for detection of aging effects. Consistent with the guidance of NUREG-1801, Enhanced Visual (VT-1 or equivalent) and/or Volumetric (RT or UT) are used to detect cracking due to SCC and cyclic loading. Fatigue of the Regenerative, Letdown, and Excess Letdown Heat Exchangers is discussed in LRA Section 4.3.2 Non-Class 1 Fatigue. It was concluded that the number of design transients are acceptable for 60 years, and therefore, management of cracking due to cyclic loading is not required.

Part 2

The One-Time Inspection Program was selected in lieu of eddy current testing of the tubes. The One-Time Inspection Program, in general, relies upon established nondestructive examination techniques of the PINGP ASME Section XI Inservice Inspection Program for detection of aging effects. Consistent with the guidance of NUREG-1801, Enhanced Visual (VT-1 or equivalent) and/or Volumetric (RT or UT) methods are used to detect cracking due to SCC. The One-Time Inspection Program uses a representative sampling approach to verify significant degradation is not occurring. Sampling is based on an assessment of material of fabrication, environment, plausible aging effects, and operating experience.

It is anticipated that the heat exchanger tubes addressed by these lines will not be selected for examination. Instead, inspections would occur on components with the equivalent material/environment combinations. As some materials and component types to be examined are not included in the PINGP ASME Section XI Inservice Inspection Program, the use of alternate examination techniques not specified by ASME Section XI may be more appropriate. In such cases, approaches equivalent to Inservice Inspection requirements will be implemented where applicable. These alternate inspection methods would include documentation of component identification, examination technique, acceptance criteria, flaw evaluation requirements and technical justification of suitability to detect the aging effects of interest. Note that the Regenerative Heat Exchanger Tubes are not within the scope of License Renewal.

Part 3

Liquid Radiation Monitor 1-R-39 (Unit 1) and 2-R-39 (Unit 2), monitor the Component Cooling System for reactor coolant leakage, including leakage from the Chemical and Volume Control System Seal Water, Letdown and Excess Letdown Heat Exchangers. These points are monitored on the plant process computer. Temperature indicators TI 15317 (Unit 1) and TI 15325 (Unit 2); and TI 15318 (Unit 1) and TI 15326 (Unit 2) are located downstream of the Letdown and Seal Water Heat Exchangers, respectively, on the Component Cooling Water side. These points are monitored on the plant process computer. Temperature elements TE-12161 (Unit 1) and TE-12165 (Unit 2) are located downstream of the Excess Letdown Heat Exchangers on the Component Cooling Water side. These points provide local indication only.

Part 4

A review of operating history did not reveal any degradation of the Regenerative, Letdown, and Excess Letdown Heat Exchanger components. Some leakage from gaskets (which are short lived and out of scope of license renewal), located on the channel heads of the heat exchangers, was noted.

Part 5

There is no record of, or requirement for, eddy current testing of the Regenerative, Letdown, and Excess Letdown Heat Exchangers. Eddy current testing of these heat exchangers would result in high doses to workers.

Part 6

The Regenerative, Letdown, and Excess Letdown Heat Exchangers were all discussed above.

RAI 3.5.2.2-1

NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Revision 1, discusses the use of ASTM Standards C227-50 and C295-54 for investigations and petrographic examinations of concrete aggregates. However, License Renewal Application (LRA) Section 3.5.2.2.2.2, “Aging Management of Inaccessible Areas – Subsection 2,” states that Prairie Island Nuclear Generating Plant (PINGP) tests and petrographic examinations were performed in accordance with ASTM Standard C289. While reviewing ASTM Standard C289 for compliance with the suggested standards, the staff noted that C289 states, “when this test method is used to evaluate the potential reactivity it must be used in combination with other methods.”

The staff requests that the applicant provide a discussion and basis for the determination that ASTM C289 by itself adequately verifies the aggregates are not reactive and satisfies the requirements of ASTM C227-50 and C295-54 as suggested by the GALL report.

NSPM Response to RAI 3.5.2.2-1

PINGP USAR Section 12.2.3.2 entitled, "Codes" provides a list of standards and specifications in use at PINGP for concrete materials. ASTM Specification C295, "Petrographic Examination" is included on the list as one method used to evaluate aggregates for reactivity. The report for concrete testing performed in June of 1968 by the Twin Cities Testing and Engineering Laboratory Inc. of St Paul, Minnesota include reactivity results for aggregates based on testing in accordance with ASTM Standard C295 and ASTM Standard C289, “Test for Potential Reactivity of Aggregates.” These test results determined that the aggregates were not potentially reactive.

LRA Section 3.5.2.2.2.2, Aging Management of Inaccessible Areas, Subsection 2, should have included ASTM Standard C295 as another one of the test methods used at PINGP to evaluate aggregates for reactivity. Because the ASTM C295 Standard was also used for PINGP, the GALL Report criterion is satisfied.

RAI 3.5.2.2-2

GALL Report line item II.A3-2 states additional inspections may be necessary to detect aging effects in dissimilar metal welds and bellows assemblies due to stress corrosion cracking (SCC), particularly if the material is not shielded from a corrosive environment. However, LRA Section 3.5.2.2.1.7, “Cracking due to Stress Corrosion Cracking (SCC),” states that additional inspections are not necessary for the stainless steel penetration sleeves and bellows with dissimilar metal welds since the components are located in a non-corrosive environment where the temperature does not reach the threshold for SCC.

The staff requests that the applicant provide (1) the highest temperature that the stainless steel penetration sleeves, penetration bellows, and dissimilar metal welds have experienced, and (2) demonstrate that chemical elements that support SCC have been monitored or measured to ensure a non-aggressive chemical environment.

NSPM Response to RAI 3.5.2.2-2

Temperatures for stainless steel penetration sleeves, penetration bellows, and dissimilar metal welds are not routinely monitored since their design is based on the maximum design temperatures expected during an accident and not the normal operating temperature. The sentence referenced by this RAI requires clarification.

Therefore, in LRA Section 3.5.2.2.1.7, the fifth sentence of the second paragraph is hereby revised to read as follows:

> “Additionally, welds are located in an air indoor environment.”

SCC is an aging mechanism that requires the simultaneous action of a corrosive environment, temperatures in excess of 140 degrees F, and a susceptible material. Elimination of any one of these elements eliminates susceptibility to SCC in accordance with EPRI guidance documents. The pressure retaining welds, dissimilar metal welds, penetration sleeves, and bellow assemblies are not exposed to a corrosive environment (see discussion on plant environment below).

The penetration sleeves, penetration bellow assemblies, and dissimilar metal welds are located inside the shield buildings in a sheltered indoor air environment, and are not located in an outdoor air or buried environment. The PINGP indoor air environment is not aggressive based on the following rationale. The plant is located in a rural area along the upper Mississippi River, and draws its cooling water from the river, a fresh water source. It is not located in a marine area and therefore not exposed to a salt air/water environment. Additionally, the U. S. Environmental Protection Agency (EPA) has established National Ambient Air Quality Standards (NAAQS) for six common pollutants (i.e., nitrogen dioxide, sulfur dioxide, carbon monoxide, lead, ozone, and particulate matter), and has designated all areas of the United States as having air quality better (“attainment”) or worse (“non-attainment”) than the NAAQS. The air quality in the area of PINGP is better than the NAAQS for all criteria pollutants (Reference PINGP LRA Environmental Report, Section 2.4). Therefore, SCC is not an aging effect requiring management since the conditions necessary for SCC do not exist.

Pressure retaining welds, dissimilar metal welds, penetration sleeves, and bellow assemblies are managed for aging effects such as cracking and loss of material by the ASME Section XI, Subsection IWE Program (Code Category E-A) and the 10 CFR Part 50 Appendix J Program (Code Category E-P) which include examination criteria adequate to detect aging effects. Any observed condition with the potential to impact an intended function is evaluated in accordance with the corrective action process.

The existing IWE inspection program elected not to implement the weld examination requirement for Code Categories E-B and E-F as allowed by 10 CFR 50.55a (b)(2)(ix)(C). Per the PINGP IWE inspection program, any accessible welds in these categories are an integral part of the liner, and as such are part of the area inspected during the performance of Category E-A examinations. Examination Category E-A requirements are considered sufficient to identify any degraded condition for containment penetration welds, dissimilar metal welds, penetration sleeves, and bellow assemblies, and therefore additional inspections are not necessary.

A review of plant operating experience identified no cracking of the penetration bellow assemblies, and reactor containment vessel leakage has not been identified as a concern.

RAI 3.6-1

Increased resistance of connections due to oxidation can occur in transmission conductors and connections, and in switchyard bus and connections. NUREG-1801, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants” (SRP-LR), Section 3.6.2.2.3, recommends a plant-specific AMP for the management of increase resistance of connections due to oxidation or loss of pre-load in transmission conductors and connections and in switchyard bus and connections.

LRA Section 3.6.2.2.3 states that there are no aging effects from the outdoor environment that would cause the loss of the capacity to provide electrical connections to specified sections of an electrical circuit to deliver voltage, current, or signals.

The staff requests that the applicant provide a basis for the applicant’s determination that increased resistance of connections due to oxidation or loss of pre-load in transmission conductors and connections, and in switchyard bus and connections is not an aging effect requiring management.

NSPM Response to RAI 3.6-1

For Transmission Cables and Conductors, high-voltage transmission conductors and connections were reviewed for aging from vibration, loss of material, wind induced abrasion, fatigue, loss of conductor strength, corrosion, increased resistance of connections, oxidation, and loss of pre-load. The PINGP Operating Experience (OE) review did not identify any aging problems with the high voltage transmission conductors and connections that resulted from vibration, wind induced abrasion, fatigue, increased resistance of connections, or loss of pre-load.

The most prevalent mechanism contributing to loss of conductor strength of an ACSR (aluminum conductor steel reinforced) transmission conductor is corrosion, which includes corrosion of the steel core and aluminum strand pitting. For ACSR conductors, degradation begins as a loss of zinc from the galvanized steel core wires. As discussed in LRA Section 3.6.2.2.3, the corrosion rates for the cable used at PINGP are within the allowable strength limit margins of the Ontario Hydroelectric test reference. The LRA section states:

> "Corrosion in ACSR conductors is a slow acting mechanism. Corrosion rates are dependent on air quality. PINGP is located in an agricultural area with no nearby industries that could contribute to corrosive air quality. Corrosion testing of transmission conductors at Ontario Hydroelectric showed a 30 percent loss of composite conductor strength of an 80-year-old ACSR conductor. The Institute of Electrical and Electronic Engineers National Electrical Safety Code (NESC) requires that tension on installed conductors be a maximum of 60% of the ultimate conductor strength. Therefore, assuming a 30% loss of strength, there would be remaining margin between what is required by the NESC and the actual conductor strength. In determining actual conductor tension, the NESC considers various loads imposed by ice, wind, and temperature as well as length of conductor span.
>
> PINGP transmission conductors in scope for License Renewal are short spans located within the PINGP site, and are designed for heavy loading; therefore, the Ontario Hydroelectric heavy loading zone study is aligned with respect to loads imposed by weather conditions.
>
> The 636 MCM ACSR transmission conductor used in the PINGP Switchyard will be used as an illustration. The ultimate strength of a 636 MCM (24/7 strands) ACSR conductor is 22,600 lbs and the maximum design tension for this conductor is 3,500 lbs. The margin between the maximum design tension and the ultimate strength is 19,100 lbs. Therefore, there is an 84.5% ultimate strength margin (19,100/22,600). The Ontario Hydroelectric study showed a 30% loss of composite conductor strength in an 80-year old conductor. Since the margin for the PINGP conductors is greater than the margin loss due to aging, remaining safety margin exists on the aged conductors.
>
> The Ontario Hydroelectric test results demonstrate that the expected material loss that would be incurred on the PINGP ACSR transmission conductors is acceptable for the period of extended operation. Therefore, no aging management is required for loss of material and loss of strength on the ACSR transmission conductors at PINGP."

For Switchyard Bus and Connections, switchyard bus connections within the component boundaries are bolted, welded and crimped aluminum connections for cables. The PINGP OE review has not identified aging problems with the high voltage switchyard bus and connections that resulted from loss of material, wind induced abrasion and fatigue loss of conductor strength, corrosion increased resistance of connections, oxidation or loss of pre-load. Bellville washers are also used at PINGP to minimize the effects of loose connections from loss of pre-load. Failures of Bellville washers (causing loose connections) were noted from industry operating experience, whereby hydrogen entrapment with plated steel washers caused embrittlement and stress cracking of the plated washer leading to loose connections. Action has been taken by the industry to correct this issue. The Prairie Island design includes the use of stainless steel Bellville washers. The issue of hydrogen entrapment causing failures is not an issue for stainless steel Bellville washers used at PINGP.

A degree of surface oxidation does initially occur on aluminum switchyard bus and connection portions exposed to Air - Outdoor environments, but the oxidation levels do not adversely impact the bus and connections from appreciable losses of material. The initial oxidation of exposed aluminum actually provides a protective layer, whereby further oxidation is progressively slowed to negligible levels. The internal contact surfaces of the switchyard bolted connections are not exposed to a moisture environment that would contribute to corrosion of the connection contact surface area. A loose connection (from any other cause, such as inadequate tightening during maintenance) is required to provide an environment for the onset of corrosion of the internal connection surfaces to occur.

For the ambient environmental conditions at the Prairie Island substation, no aging effects have been identified for switchyard bus and connections that could cause a loss of intended function for the extended period of operation. Therefore, there are no applicable or significant aging effects for the aluminum bus and aluminum alloy connections that require aging management. As a result, no plant specific license renewal aging management program is required for Transmission Cables and Conductors, and Switchyard Bus and Connections.

RAI 3.6-2

Tie wraps may be taken credit for in seismic analysis and in plant design specifications primarily for separation of cables to preclude ampacity degrading. Operating experience has identified occurrences where tie wraps have become brittle, degraded, or are missing and whose failures have affected the safety functions of other system/components.

The PINGP LRA does not address tie wraps as a commodity type which has been reviewed to determine if tie wraps are within the scope of license renewal and subject to an aging management review (AMR).

The staff requests that the applicant explain the basis for determining that tie wraps are not within the scope of license renewal and not subject to an AMR. In particular, address if tie wraps are taken credit for in seismic analysis or/and design specifications in the current licensing basis. Address whether tie wraps are used in applications where they are non-safety related components, whose failure could affect safety-related intended functions. If tie wraps are taken credit for in a seismic analysis, provide a quantitative analysis of the effects of cables spacing not being maintained as original design specifications (due to tie wraps failure). The analysis should provide the worst case scenario with ampacity reduction and the maximum amperes required for motors to start and run during a design basis accident.

NSPM Response to RAI 3.6-2

The use of tie wraps at PINGP has been reviewed, and it is confirmed that tie wraps are not within the scope of license renewal and not subject to an AMR.

Debris Considerations

Industry and PINGP OE were reviewed. Foreign material debris, such as broken tie wraps, can cause equipment functional failures. PINGP equipment that is sensitive to debris, such as broken tie wraps, are designed to be protected by enclosures. Maintenance-induced failures from inadequate foreign material exclusion (FME) practices involving tie wraps do not bring tie wraps in scope and do not require AMR for License Renewal purposes. An analysis of the containment sump for the safety-related recirculation mode of post-accident operation, considered the effects of debris, including tie wraps. No occurrences were identified involving a non-safety related tie wrap failure affecting safety-related intended functions at PINGP.

Seismic Support Considerations

Tie wraps are used to assist in the orderly installation of cables in tray at PINGP. Tie wraps are not credited for support in the PINGP seismic analyses

Ampacity Considerations

PINGP USAR Section 8.7 states "They [power cables] are installed with only a single layer of cables per tray and clamped in the ladder to ensure that a specified spacing exists between these cables to ensure that air cooling is available."

The LR project conducted a cable insulation aging assessment for the hypothetical configuration of unspaced single layer power cables in trays with continuous heavy current loading for motors credited to start and run during a design basis accident. For the continuous heavy current loaded power cables the free-air rating was based on IPCEA P-46-426, ICPA P-54-440, and the NEC. For each of the continuous heavy current loaded power cables, the full load amps or actual amps value was obtained. An aging assessment screening derate factor of 50% was applied to the power cables' free air allowable ampacity value. No continuous heavily loaded power cables in scope of License Renewal were identified to be operating at or above 50% of free air allowable ampacity. The aging assessment concluded that power cables have adequate design margin to accommodate a hypothetical not spaced configuration, 60 years of operational aging, and to start and run credited motors during a design basis accident.

The following example illustrates the process used for aging assessments. A power cable to a Charging Pump Motor, 125 HP (460V), operates at 145 amps full load. The 3/C 4/0 copper allowable ampacity for free air is 359 amps. The 145 full load amps drawn by the motor is 40% of the free air allowable ampacity of the cable. (The free air allowable ampacity values, as well as derating criteria, reside in IPCEA P-46-426, ICPA P-54-440, and the NEC.)

Enclosure 2

Updated Preliminary License Renewal Commitment List

13 Pages

Preliminary License Renewal Commitments

The following table provides the list of preliminary commitments included in the Application for Renewed Operating Licenses (LRA) for Prairie Island Nuclear Generating Plant (PINGP) Units 1 and 2. These commitments reflect the contents of the LRA as submitted, and any updates provided in subsequent correspondence, but are considered preliminary in that the specific wording of some commitments may change, and additional commitments may be made, during the NRC review of the LRA.

The final commitments as submitted by NSPM, and accepted by NRC, are expected to be confirmed in the NRC's Safety Evaluation Report (SER) for the renewed operating licenses. The final commitments, as confirmed in the SER, will become effective upon NRC issuance of the renewed operating licenses. In addition, as stated in the LRA, the final commitments will be incorporated into the Updated Safety Analysis Report (USAR).

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
1	Each year, following the submittal of the PINGP License Renewal Application and at least three months before the scheduled completion of the NRC review, NMC will submit amendments to the PINGP application pursuant to 10 CFR 54.21(b). These revisions will identify any changes to the Current Licensing Basis that materially affect the contents of the License Renewal Application, including the USAR supplements.	12 months after LRA submittal date and at least 3 months before completion of NRC review	1.4
2	Following the issuance of the renewed operating license, the summary descriptions of aging management programs and TLAAs provided in Appendix A, and the final list of License Renewal commitments, will be incorporated into the PINGP USAR as part of a periodic USAR update in accordance with 10 CFR 50.71(e). Other changes to specific sections of the PINGP USAR necessary to reflect a renewed operating license will also be addressed at that time.	First USAR update in accordance with 10 CFR 50.71(e) following issuance of renewed operating licenses	A1.0
3	An Aboveground Steel Tanks Program will be implemented. Program features will be as described in LRA Section B2.1.2.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.2
4	Procedures for the conduct of inspections in the External Surfaces Monitoring Program, Structures Monitoring Program, Buried Piping and Tanks Inspection Program, and the RG 1.127	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.6

Preliminary License Renewal Commitments

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
	Inspection of Water-Control Structures Associated with Nuclear Power Plants Program will be enhanced to include guidance for visual inspections of installed bolting.		
5	A Buried Piping and Tanks Inspection Program will be implemented. Program features will be as described in LRA Section B2.1.8.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.8
6	The Closed-Cycle Cooling Water System Program will be enhanced to include periodic inspection of accessible surfaces of components serviced by closed-cycle cooling water when the systems or components are opened during scheduled maintenance or surveillance activities. Inspections are performed to identify the presence of aging effects and to confirm the effectiveness of the chemistry controls. Visual inspection of component internals will be used to detect loss of material and heat transfer degradation. Enhanced visual or volumetric examination techniques will be used to detect cracking. [Revised in letter dated 1/20/2009 in response to RAI 3.3.2-13-01]	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.9
7	The Compressed Air Monitoring Program will be enhanced to require that Station and Instrument Air System air quality be monitored and maintained in accordance with the instrument air quality guidance provided in ISA S7.0.01-1996. Particulate testing will be revised to use a particle size methodology as specified in ISA S7.0.01.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.10
8	An Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program will be completed. Program features will be as described in LRA Section B2.1.11.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.11

Preliminary License Renewal Commitments

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
9	An Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program will be implemented. Program features will be as described in LRA Section B2.1.12.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.12
10	An Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program will be implemented. Program features will be as described in LRA Section B2.1.13.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.13
11	The External Surfaces Monitoring Program will be enhanced as follows: • The scope of the program will be expanded as necessary to include all metallic and non-metallic components within the scope of license renewal that require aging management in accordance with this program. • The program will ensure that surfaces that are inaccessible or not readily visible during plant operations will be inspected during refueling outages. • The program will ensure that surfaces that are inaccessible or not readily visible during both plant operations and refueling outages will be inspected at intervals that provide reasonable assurance that aging effects are managed such that the applicable components will perform their intended function during the period of extended operation.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.14
12	The Fire Protection Program will be enhanced to require periodic visual inspection of the fire barrier walls, ceilings, and floors to be performed during walkdowns at least once every refueling cycle. [Revised in letter dated 12/5/2008 in response to RAI B2.1.15-3]	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.15

Preliminary License Renewal Commitments

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
13	The Fire Water System Program will be enhanced as follows: • The program will be expanded to include eight additional yard fire hydrants in the scope of the annual visual inspection and flushing activities. • The program will require that sprinkler heads that have been in place for 50 years will be replaced or a representative sample of sprinkler heads will be tested using the guidance of NFPA 25, "Inspection, Testing and Maintenance of Water-Based Fire Protection Systems" (2002 Edition, Section 5.3.1.1.1). Sample testing, if performed, will continue at a 10-year interval following the initial testing.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.16
14	The Flux Thimble Tube Inspection Program will be enhanced as follows: • The program will require that the interval between inspections be established such that no flux thimble tube is predicted to incur wear that exceeds the established acceptance criteria before the next inspection. • The program will require that re-baselining of the examination frequency be justified using plant-specific wear rate data unless prior plant-specific NRC acceptance for the re-baselining was received. If design changes are made to use more wear-resistant thimble tube materials, sufficient inspections will be conducted at an adequate inspection frequency for the new materials. • The program will require that flux thimble tubes that cannot be inspected must be removed from service.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.18

Preliminary License Renewal Commitments

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
15	The Fuel Oil Chemistry Program will be enhanced as follows: • Particulate contamination testing of fuel oil in the eleven fuel oil storage tanks in scope of License Renewal will be performed, in accordance with ASTM D 6217, on an annual basis. • One-time ultrasonic thickness measurements will be performed at selected tank bottom and piping locations prior to the period of extended operation.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.19
16	A Fuse Holders Program will be implemented. Program features will be as described in LRA Section B2.1.20.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.20
17	An Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program will be implemented. Program features will be as described in LRA Section B2.1.21	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.21
18	An Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program will be implemented. Program features will be as described in LRA section B2.1.22.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.22
19	The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program will be enhanced as follows: • Program implementing procedures will be revised to ensure the components and structures subject to inspection are clearly identified. Program inspection procedures will be enhanced to include the parameters corrosion and wear where omitted.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.23

Preliminary License Renewal Commitments

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
20	A Metal-Enclosed Bus Program will be implemented. Program features will be as described in LRA Section B2.1.26.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.26
21	For the Nickel-Alloy Nozzles and Penetrations Program, PINGP commits to the following activities for managing the aging of nickel-alloy components susceptible to primary water stress corrosion cracking: • Comply with applicable NRC orders, and • Implement applicable NRC Bulletins, Generic Letters, and staff-accepted industry guidelines.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.27
22	The Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program will be enhanced as follows: • The program will require that any deviations from implementing the appropriate required inspection methods of the NRC First Revised Order EA-03-009, “Issue of Order Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors,” dated February 20, 2004 (Order), as amended, will be submitted for NRC review and approval in accordance with the Order, as amended. • The program will require that any deviations from implementing the required inspection frequencies mandated by the Order, as amended, will be submitted for NRC review and approval in accordance with the Order, as amended. • The program will require that relevant flaw indications detected during the augmented inspections of the upper vessel head penetration nozzles will be evaluated in	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.28

Preliminary License Renewal Commitments

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
	accordance with the criteria provided in the letter from Mr. Richard Barrett, NRC, Office of Nuclear Reactor Regulation (NRR), Division of Engineering to Alex Marion, Nuclear Energy Institute (NEI), dated April 11, 2003, or in accordance with NRC-approved Code Cases that incorporate the flaw evaluation procedures and criteria of the NRC's April 11, 2003, letter to NEI. • The program will require that, if leakage or evidence of cracking in the vessel head penetration nozzles (including associated J-groove welds) is detected while ranked in the “Low,” “Moderate,” or “Replaced” susceptibility category, the nozzles are to be immediately reclassified to the “High” susceptibility category and the required augmented inspections for the “High” susceptibility category are to be implemented during the same outage the leakage or cracking is detected.		
23	A One-Time Inspection Program will be completed. Program features will be as described in LRA Section B2.1.29.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.29
24	A One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program will be completed. Program features will be as described in LRA Section B2.1.30.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.30
25	For the PWR Vessel Internals Program, PINGP commits to the following activities for managing the aging of reactor vessel internals components: • Participate in the industry programs for investigating and managing aging effects on reactor internals; • Evaluate and implement the results of the industry programs as applicable to the reactor internals; and	U1 - 8/9/2011 U2 - 10/29/2012	B2.1.32

Preliminary License Renewal Commitments

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
	• Upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.		
26	The Reactor Head Closure Studs Program will be enhanced to incorporate controls that ensure that any future procurement of reactor head closure studs will be in accordance with the material and inspection guidance provided in NRC Regulatory Guide 1.65.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.33
27	The Reactor Vessel Surveillance Program will be enhanced as follows: • A requirement will be added to ensure that all withdrawn and tested surveillance capsules, not discarded as of August 31, 2000, are placed in storage for possible future reconstitution and use. • A requirement will be added to ensure that in the event spare capsules are withdrawn, the untested capsules are placed in storage and maintained for future insertion.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.34
28	The RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program will be enhanced as follows: • The program will include inspections of concrete and steel components that are below the water line at the Screenhouse and Intake Canal. The scope will also require inspections of the Approach Canal, Intake Canal, Emergency Cooling Water Intake, and	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.35

Preliminary License Renewal Commitments

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
	Screenhouse immediately following extreme environmental conditions or natural phenomena including an earthquake, flood, tornado, severe thunderstorm, or high winds. • The program parameters to be inspected will include an inspection of water-control concrete components that are below the water line for cavitation and erosion degradation. • The program will visually inspect for damage such as cracking, settlement, movement, broken bolted and welded connections, buckling, and other degraded conditions following extreme environmental conditions or natural phenomena.		
29	A Selective Leaching of Materials Program will be completed. Program features will be as described in LRA B2.1.36.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.36
30	The Structures Monitoring Program will be enhanced as follows: • The following structures, components, and component supports will be added to the scope of the inspections: o Approach Canal o Fuel Oil Transfer House o Old Administration Building and Administration Building Addition o Component supports for cable tray, conduit, cable, tubing tray, tubing, non-ASME vessels, exchangers, pumps, valves, piping, mirror insulation, non-ASME valves, cabinets, panels, racks, equipment enclosures, junction boxes, bus	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.38

Preliminary License Renewal Commitments

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
	ducts, breakers, transformers, instruments, diesel equipment, housings for HVAC fans, louvers, and dampers, HVAC ducts, vibration isolation elements for diesel equipment, and miscellaneous electrical and mechanical equipment items o Miscellaneous electrical equipment and instrumentation enclosures including cable tray, conduit, wireway, tube tray, cabinets, panels, racks, equipment enclosures, junction boxes, breaker housings, transformer housings, lighting fixtures, and metal bus enclosure assemblies o Miscellaneous mechanical equipment enclosures including housings for HVAC fans, louvers, and dampers o SBO Yard Structures and components including SBO cable vault and bus duct enclosures. o Fire Protection System hydrant houses o Caulking, sealant and elastomer materials o Non-safety related masonry walls that support equipment relied upon to perform a function that demonstrates compliance with a regulated event(s). • The program will be enhanced to include additional inspection parameters. • The program will require an inspection frequency of once every five (5) years for structures and structural components within the scope of the program. The frequency of inspections can be adjusted, if necessary, to allow for early detection and timely correction of negative trends.		

Preliminary License Renewal Commitments

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
	• The program will require periodic sampling of groundwater and river water chemistries to ensure they remain non-aggressive.		
31	A Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program will be implemented. Program features will be as described in LRA Section B2.1.39.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.39
32	The Water Chemistry Program will be enhanced as follows: • The program will require increased sampling to be performed as needed to confirm the effectiveness of corrective actions taken to address an abnormal chemistry condition. • The program will require Reactor Coolant System dissolved oxygen Action Level limits to be consistent with the limits established in the EPRI PWR Primary Water Chemistry Guidelines." [Revised in letter dated 12/5/2008 in response to RAI B2.1.40-3]	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.40
33	The Metal Fatigue of Reactor Coolant Pressure Boundary Program will be enhanced as follows: • The program will monitor the six component locations identified in NUREG/CR-6260 for older vintage Westinghouse plants, either by tracking the cumulative number of imposed stress cycles using cycle counting, or by tracking the cumulative fatigue usage, including the effects of coolant environment. The following locations will be monitored: o Reactor Vessel Inlet and Outlet Nozzles o Reactor Pressure Vessel Shell to Lower Head	U1 - 8/9/2013 U2 - 10/29/2014	B3.2

Preliminary License Renewal Commitments

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
	o RCS Hot Leg Surge Line Nozzle o RCS Cold Leg Charging Nozzle o RCS Cold Leg Safety Injection Accumulator Nozzle o RHR-to-Accumulator Piping Tee • Program acceptance criteria will be clarified to require corrective action to be taken before a cumulative fatigue usage factor exceeds 1.0 or a design basis transient cycle limit is exceeded. [Revised in letter dated 1/9/2009 in response to RAI 4.3.1.1-1]		
34	Reactor internals baffle bolt fatigue transient limits of 1835 cycles of plant loading at 5% per minute and 1835 cycles of plant unloading at 5% per minute will be incorporated into the Metal Fatigue of Reactor Coolant Pressure Boundary Program and USAR Table 4.1-8.	U1 - 8/9/2013 U2 - 10/29/2014	B3.2
35	NSPM will perform an ASME Section III fatigue evaluation of the lower head of the pressurizer to account for effects of insurge/outsurge transients. The evaluation will determine the cumulative fatigue usage of limiting pressurizer component(s) through the period of extended operation. The analyses will account for periods of both “Water Solid” and “Standard Steam Bubble” operating strategies. Analysis results will be incorporated, as applicable, into the Metal Fatigue of Reactor Coolant Pressure Boundary Program. [Revised in letter dated 1/9/2009 in response to RAI 4.3.1.1-1]	U1 - 8/9/2013 U2 - 10/29/2014	4.3.1.3
36	NSPM will complete fatigue calculations for the pressurizer surge line hot leg nozzle and the charging nozzle using the methodology of the ASME Code (Subsection NB) and will	April 30, 2009	4.3.3

Preliminary License Renewal Commitments

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
	report the revised CUFs and CUFs adjusted for environmental effects at these locations as an amendment to the PINGP LRA. Conforming changes to LRA Section 4.3.3, "PINGP EAF Results," will also be included in that amendment to reflect analysis results and remove references to stress-based fatigue monitoring. [Added in letter dated 1/9/2009 in response to RAI 4.3.1.1-1]		

January 20, 2009

L-PI-09-006
10 CFR 54

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

Prairie Island Nuclear Generating Plant Units 1 and 2
Dockets 50-282 and 50-306
License Nos. DPR-42 and DPR-60

Responses to NRC Requests for Additional Information Dated December 18, 2008 Regarding Application for Renewed Operating Licenses

By letter dated April 11, 2008, Northern States Power Company, a Minnesota Corporation, (NSPM) submitted an Application for Renewed Operating Licenses (LRA) for the Prairie Island Nuclear Generating Plant (PINGP) Units 1 and 2. In a letter dated December 18, 2008, the NRC transmitted Requests for Additional Information (RAIs) regarding that application. This letter provides responses to those RAIs.

Enclosure 1 provides the text of each RAI followed by the NSPM response.

Enclosure 2 provides an updated version of the Preliminary License Renewal Commitment List contained in the LRA transmittal letter. This updated list reflects changes made to date in the various NSPM letters responding to NRC RAIs.

If there are any questions or if additional information is needed, please contact Mr. Eugene Eckholt, License Renewal Project Manager.

Summary of Commitments

This letter contains no new commitments. Commitment No. 6 in the list of Preliminary License Renewal Commitments contained in the LRA transmittal letter dated April 11, 2008, is revised to read as follows:

> The Closed-Cycle Cooling Water System Program will be enhanced to include periodic inspection of accessible surfaces of components serviced by closed-cycle cooling water when the systems or components are opened during scheduled maintenance or surveillance activities. Inspections are performed to identify the presence of aging effects and to confirm the effectiveness of the chemistry controls. Visual inspection of component internals will be used to detect loss of material and heat transfer degradation. Enhanced visual or volumetric examination techniques will be used to detect cracking.

1717 Wakonade Drive East • Welch, Minnesota 55089-9642
Telephone: 651.388.1121

I declare under penalty of perjury that the foregoing is true and correct.
Executed on January 20, 2009.

/S/ Michael D. Wadley

Michael D. Wadley
Site Vice President, Prairie Island Nuclear Generating Plant Units 1 and 2
Northern States Power Company - Minnesota

Enclosures (2)

cc:

Administrator, Region III, USNRC
License Renewal Project Manager, Prairie Island, USNRC
Resident Inspector, Prairie Island, USNRC
Prairie Island Indian Community ATTN: Phil Mahowald
Minnesota Department of Commerce

Enclosure 1
NSPM Responses to NRC Requests for Additional Information
Dated December 18, 2008

RAI 3.1.1-1

In LRA Table 3.1.2-03, two AMR line items references the following:

- Table 1 item 3.1.1-80 and GALL Report Volume 2 line item IV.B2-21

For these line items, the GALL Report recommends that AMP XI.M13, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)," be used for managing the aging effects of loss of fracture toughness due to thermal aging and neutron irradiation embrittlement. However Table 1 item 3.1.1-80 credits the PINGP B2.1.32, "PWR Vessels Internal Program." Please justify the basis for using the PINGP AMP B2.1.32, "PWR Vessels Internal Program," in lieu of the GALL Report recommended program.

NSPM Response to RAI 3.1.1-1

The NUREG-1801, XI.M13 Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program consists of two major parts:

- Initially the program requires the identification of susceptible components determined to be limiting from the standpoint of thermal aging susceptibility based on ferrite and molybdenum contents, casting process, and operating temperature; and/or neutron irradiation embrittlement (neutron fluence). Note that the material composition of the PINGP CASS BMI Column Cruciforms could not be determined, and therefore, they were assumed to be susceptible to thermal embrittlement and required to be managed for reduction of fracture toughness. Radiation levels are significant enough that the components are susceptible to radiation embrittlement.

- Subsequently, for each potentially susceptible component, aging management under NUREG-1801, XI.M13 would be accomplished through either a supplemental examination of the affected component based on the neutron fluence to which the component has been exposed, as part of the applicant's 10-year inservice inspection (ISI) program during the license renewal term, or a component-specific evaluation to determine its susceptibility to loss of fracture toughness. Flaws detected in CASS components are evaluated in accordance with the applicable procedures of IWB-3500. A flaw tolerance evaluation for components with ferrite content up to 25% is performed according to the principles associated with IWB-3640 procedures for submerged arc welds (SAW), disregarding the Code restriction of 20% ferrite in IWB-3641(b)(1).

The PINGP PWR Vessel Internals Program described in LRA Section B2.1.32 addresses the long term management of aging effects in the reactor vessel internals (RVI) components. The scope of the program includes the inspection plan and all related commitments and actions for monitoring, evaluation, and repair/replacement of components to manage the aging effects for reactor vessel internals components, thereby maintaining their ability to perform their intended function. The program consists of identifying the most susceptible or limiting components and developing appropriate inspection techniques. The program monitors the effects of aging degradation mechanisms on the intended function of reactor vessel internals components through one-time, periodic, and conditional examinations, and other aging management program elements, as needed, in accordance with the ASME Code, Section XI, and the guidelines established by the EPRI Materials Reliability Program (MRP) for PWR internals.

Preliminary License Renewal Commitment #25 commits to the following activities for managing the aging of reactor vessel internals components:

- Participate in the industry programs for investigating and managing aging effects on reactor internals
- Evaluate and implement the results of the industry programs as applicable to the reactor internals
- Upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.

The PWR Vessel Internals Program manages reduction of fracture toughness in reactor vessel internals components. Loss of fracture toughness is of consequence only if cracks exist. Cracking is expected to initiate at the surface and is detectable by augmented inspection. If the program identifies the BMI Column Cruciforms to be a susceptible or limiting component, then the program would develop appropriate inspection techniques. Currently, the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program conducts a visual VT-3 examination of the reactor vessel removable core support structures under Table IWB-2500-1, Examination Category B-N-3, once per Inservice Inspection interval.

The PINGP PWR Vessel Internals Program will include acceptance criteria established in the MRP guidelines. Any condition that is detected that does not satisfy the acceptance criteria must be evaluated. For ASME Code Section XI components the evaluation must be in accordance with ASME Code Section XI requirements. For non-ASME Code Section XI components, the recommendations provided in the MRP guidelines may be used.

The PINGP PWR Vessel Internals Program consists of identifying the most susceptible components and developing inspection techniques in the same way the NUREG-1801, XI.M13 Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program does. Implementation of the PWR Vessel Internals Program will provide reasonable assurance that aging effects will be managed such that components within the scope of this program will continue to perform their intended function(s) during the period of extended operation and is therefore an acceptable substitution for NUREG-1801, AMP XI.M13, “Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS).”

RAI 3.1.2-02

In the LRA 3.X.2 Tables, the applicant has assigned "Note E" to several line items for cast austenitic stainless steel components exposed to a treated water environment. The aging effect that requires management for these components is Cracking – SCC/Intergranular Attack (IGA). These components are: Piping/Fittings (Table 3.1.2-02), Pump Casings (Table 3.1.2-02), Valve Bodies (Table 3.1.2-02), Valve Bodies (Table 3.2.2-02), and Valve Bodies (Table 3.2.2-03). The GALL Report Table IV.C2, AMR item IV.C2-3 recommends monitoring and control of water chemistry in accordance with EPRI TR-105714 and material selection according to NUREG-0313, Rev 2, where reduced susceptibility to SCC is expected if carbon content is 0.035% or less and delta ferrite content is 7.5%. The GALL AMR states that if Cast Austenitic Stainless Steel (CASS) components do not meet either one of the two guidelines, then a plant specific program is to be evaluated that includes inspection methods to detect cracking and flaw evaluation of components susceptible to thermal embrittlement. The applicant credits the ASME Section XI ISI, IWB, IWC, and IWD program to manage cracking.

1) For these components, clarify whether PINGP controls water chemistry in accordance with the guidelines in EPRI Report No. TR-105714.
2) Clarify how the CASS components in these LRA AMR items meet the SCC susceptibility considerations of having less than an 0.035% carbon alloying content or less than a 0.75% delta ferrite content.
3) If it is determined that any of these CASS components do not meet the reduced susceptibility criteria on carbon and delta ferrite alloy contents, discuss the inspection methods that will be used to monitor for cracking in these components. Discuss the flaw evaluation methodologies used by PINGP to account for a change in the critical crack size used in the analysis as a result of a drop in the fracture toughness of the CASS components.
4) Ultrasonic testing (UT) methods may be incapable of detecting flaws in CASS components because of the dense, small grain-size microstructure of CASS, which results in significant, high amplitude UT background noise signals. If UT is proposed as the method for inspecting these components, provide your basis why the UT method selected would be capable of distinguishing between a UT signal that results from a flaw in the material as opposed to background UT signals that result from the CASS microstructure or abnormal geometries in the CASS component.

Clarify whether or not the inspection methods and flaw evaluation methods implemented for these components are within the scope of the PINGP ASME Section XI Inservice Inspection Program.

NSPM Response to RAI 3.1.2-02

Part 1

For the component types and AMR line items discussed in this RAI, PINGP credits the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and the Water Chemistry Program to manage cracking due to SCC/IGA of CASS components exposed to a treated water environment. For the subject components, the Water Chemistry Program controls water chemistry in accordance with Revision 5 of the "PWR Primary Water Chemistry Guidelines", EPRI TR-1002884, for primary and auxiliary water systems. EPRI TR-1002884 is a later revision of EPRI Report No. TR-105714.

Earlier revisions of the "PWR Primary Water Chemistry Guidelines", such as Revision 3, were numbered as EPRI TR-105714. Earlier revisions are cited in the GALL using the EPRI TR-105714 designator, with the exception of one reference to EPRI TR-1002884 contained in the reference list of Section XI.M2 of NUREG-1801. Though earlier revisions of both the primary and secondary water chemistry guidelines are cited in the GALL, the GALL also recognizes the use of later revisions. Therefore, use of later revisions is not considered an exception to NUREG-1801.

Part 2

The carbon alloying and delta ferrite content of the PINGP CASS reactor coolant components is either unknown or typically greater than the 0.035% carbon alloying content and the 7.5% delta ferrite which is discussed in NUREG-1801, Item No. IV.C2-3. However, NUREG-1801, Item No. IV.C2-3, allows an option for a plant-specific aging management program for CASS components that do not meet either of these guidelines. PINGP chose to use the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program for aging management in addition to the Water Chemistry Program.

Part 3

The PINGP ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program currently provides for volumetric examinations of reactor coolant piping and fittings in accordance with the Risk-Informed Inservice Inspection Program. ASME Section XI, Examination Category B-L-1 requires VT-1 visual examination of pressure retaining welds in pump casings. Examination Category B-L-2 requires VT-3 visual examination of pump casing internal surfaces, if disassembled. Examination Category B-M-2 requires VT-3 visual examination of internal surfaces of valve bodies, if disassembled. In addition, Examination Category B-P requires visual (VT-2) examination of all pressure retaining piping components. The PINGP ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is updated periodically as required by 10 CFR 50.55a, which is described further in the Response to RAI B2.1.3-1 in the NSPM letter dated December 18, 2008.

The PINGP Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program will identify the CASS piping components in the Reactor Coolant System potentially susceptible to thermal aging embrittlement and provide enhanced volumetric examinations on the base metal determined to be limiting due to applied stress, operating time, and environmental considerations using examination methods that meet the criteria of ASME Section XI, Appendix VIII. Alternatively, component-specific flaw tolerance evaluations will be performed using specific geometry and applied stress to demonstrate that the thermally-embrittled material has adequate toughness.

Flaws detected in CASS components will be evaluated in accordance with the applicable procedures of ASME Section XI, Subsections IWB-3500 or IWC-3500 under the PINGP ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. Alternatively, flaw tolerance evaluation for components with ferrite content up to 25% will be performed according to the principles associated with IWB-3640 procedures for submerged arc welds disregarding the Code restriction of 20% ferrite in IWB-3641(b)(1).

Part 4

The PINGP procedure for ultrasonic examination of cast stainless steel main coolant pipe welds is based on WCAP-11778, “Demonstration of Flaw Detection and Characterization Capabilities for Ultrasonic Examination of Main Coolant Loop Welds,” March 1988, prepared by Westinghouse. The report describes the development of improved manual ultrasonic inspection techniques, and the optimization and qualification of manual ultrasonic flaw detection and characterization capabilities. The WCAP recognized that inspection of heavy-wall austenitic stainless steel components is difficult. The large grain sizes and the various levels of anisotropy lead to severe attenuation, wave velocity changes, and dispersive scattering of sound energy. These factors may result in mislocation of detected defects, specific volumes of material not being examined, and reflections from grain boundaries which may be interpreted as defects. However the ultrasonic testing is not impossible if measures are taken to avoid these factors which include knowledge of fabrication materials to be inspected, adequate surface preparation, knowledge of defects, sufficient training for inspection personnel, improved understanding of the sound beam propagation mechanism, appropriate selection of ultrasonic test equipment, and demonstration of the ultrasonic test procedures. PINGP ultrasonic examination procedures incorporate the research done by WCAP-11778 to improve the ultrasonic inspection of the cast austenitic stainless steel reactor coolant piping.

The PINGP procedure for ultrasonic examination of cast stainless steel main coolant pipe welds contains the following acceptance criteria to ensure the recording of any suspected flaws:

A. For straight beam examinations:

    1. All reflectors are to be recorded at the primary reference sensitivity.

2. All reflectors that equal or exceed 20% full screen height will be recorded in addition to any loss of back reflection greater than 50% that is not attributable to geometry.

B. For angle beam examinations the following are required:

1. All reflectors are to be recorded at the primary reference sensitivity.

2. All reflectors suspected to be a flaw shall be recorded regardless of amplitude or size.

3. All reflectors with amplitudes that exceed 20% distance amplitude correction (DAC) are to be evaluated to the extent that the operator can determine their shape, identity and location, source and cause to determine if they are valid or non-valid indications.

   - Valid indications are reflectors caused by flaws such as cracks, lack of penetration and embedded volumetric type discontinuities. For reactor coolant pipe longitudinal and circumferential welds, valid reflectors should appear distinct from material noise by an amplitude ratio of 2:1 with "travel" observed while scanning toward and away from the reflector. Such reflectors should have measurable length to be considered a recordable indication.

   - Non-valid indications include those due to material grain noise, beam redirection and mode conversion, weld or buttering interface and geometric reflectors.

4. All valid reflectors exceeding 20% DAC are to be evaluated and recorded to the extent that their shape, identity and location, can be determined for acceptance/rejection in accordance with ASME Section XI, IWB-3000.

5. All geometric reflectors, with amplitudes that exceed 20% DAC, are to be recorded (maximum amplitude, location, and what is causing reflector). The indications are to be evaluated to the extent that the operator can determine their shape, identity and location. For a reflector to be defined as geometric, the evaluation will be confirmed by the following:

   - Review of radiographs.

   - Review of weld joint design.

   - Previous examination results.

   - Perform cross sectional plot of the position of the indication by performing the following:

a. Obtain the OD weld profile (using contour gage) and the ID surface contour (using multiple thickness readings) to construct a cross sectional sketch at the maximum amplitude indication location.

b. Once the sketch of the component is constructed it will be utilized to plot the actual position of the reflector using the proper angle, transducer position and metal path.

Continuing investigations to improve the ultrasonic inspection of the cast austenitic stainless steel reactor coolant piping are focused on improving our knowledge of reactor coolant loop materials, specifically in the areas of material characterization and of their effect on ultrasonic beams. These investigations are ongoing in the industry and any improvements in the testing will be adopted by PINGP.

RAI 3.1.2-2-01

LRA Section: Table 3.1.2-2, page 3.1-70, page 3.1-71

Background: In LRA Table 3.1.2-2, on page 3.1-70, the AMR results for stainless steel valve bodies in a treated water environment show the aging effect of cracking managed by three AMPs: 1) ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program; 2) One-Time Inspection Program; and 3) Water Chemistry Program. The AMR result line for the Water Chemistry Program references three different GALL Report Volume 2 line items and three corresponding LRA Table 1 line items. The ASME Section XI, Subsections IWB, IWC, and IWD Program and the One-Time Inspection Program line items each reference one of the GALL Report Volume 2 line items and corresponding Table 1 line items.

Similarly, on page 3.1-71, the AMR results for stainless steel valve bodies in a treated water environment show aging effects of loss of material due to crevice or pitting corrosion managed by two AMPs: 1) One-Time Inspection Program; and 2) Water Chemistry Program. Again the line item for the Water Chemistry Program references multiple GALL Report Volume 2 and LRA Table 1 line items, but only one of the GALL Report Volume 2 line items is referenced by the Water Chemistry Program line item.

Issue: To compare AMR results in the LRA against recommended AMR results in the GALL Report, it is necessary to have a clear methodology to determine what AMP or combination of AMPs is proposed to manage the aging effect for each component, material, environment and aging effect (MEA) combination listed. However, the LRA provides no additional guidance on how an AMP line with multiple GALL Report Volume 2 line item references should be combined with companion AMP lines that refer to only one of those GALL Report line items, so that the AMP or AMPs proposed for each MEA combination is uniquely determined.

Request:

1) Provide additional guidance on how AMP lines referring to multiple GALL Report Volume 2 line items are to be combined with companion AMP lines to uniquely determine the AMP or combination of AMPs being proposed to manage the aging effect for a specific MEA combination.

2) Give specific examples of how this guidance is to be applied using the three AMR result lines at the bottom of LRA page 3.1-70 and the AMR result lines on LRA page 3.1-71.

NSPM Response to RAI 3.1.2-2-01

Part 1

The components in the Reactor Coolant System are primarily ASME Class I, reactor coolant pressure boundary components exposed to treated borated water and reference NUREG-1801 Chapter IV. However, the Reactor Coolant System also contains components which are not reactor coolant pressure boundary components and are exposed to either a treated borated water environment (NUREG-1801, Chapter V) or a demineralized water environment (NUREG-1801, Chap VIII). Therefore, in order to find appropriate aging management, PINGP utilized NUREG-1801 lines in other Chapters that included component/material/environment combinations which covered these components. To identify the different components, environments and the corresponding aging management programs applicable to the given component, the matched NUREG-1801 Volume 2 line items are to be combined. See the following examples.

Part 2

For the stainless steel RCS valve bodies shown on LRA Page 3.1-70 exposed to Treated Water (Int) and susceptible to cracking due to SCC/IGA: ASME Class 1 Reactor Coolant Pressure Boundary valves exposed to treated borated water are managed by ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD and Water Chemistry Programs in accordance with line item IV.C2-2. Valves exposed to demineralized water are managed by One-Time Inspection and Water Chemistry Programs in accordance with line Item VIII.E-30. Valves exposed to a treated borated water environment, but which are not reactor coolant pressure boundary components, are managed by the Water Chemistry Program in accordance with line Item V.D1-31.

For the stainless steel RCS valve bodies shown on LRA Page 3.1-71 exposed to Treated Water (Int) and susceptible to loss of material due to crevice or pitting corrosion: ASME Class 1 Reactor Coolant Pressure Boundary valves exposed to treated borated water are managed by the Water Chemistry Program in accordance with line item IV.C2-15. Valves exposed to demineralized water are managed by One-Time Inspection and Water Chemistry Programs in accordance with line Item VIII.E-29. Valves exposed to a treated borated water environment, but which are not reactor coolant pressure boundary components, are managed by the Water Chemistry Program in accordance with line Item V.D1-30.

RAI 3.1.2-5-01

LRA Section: Table 3.1.2-5, pages 3.1-128 and -129

Background: Table 3.1.2-5 (Steam Generator System) shows AMR results for nickel alloy U-tubes in a treated water environment with an aging effect of heat transfer degradation due to fouling. Note H is cited indicating that the aging effect is not included in the GALL Report for this component, material and environment combination. The recommended AMP is the Water Chemistry Program, alone.

Issue: The LRA does not provide any justification as to why the Water Chemistry Program, alone, is sufficient to provide management for this aging effect during the period of extended operation. Also, GALL Report Volume 2, line item V.A-16, which is for stainless steel heat exchanger tubes in a treated water environment, recommends use of Water Chemistry and One-Time Inspection to manage the aging effect of reduction of heat transfer due to fouling. Although the materials are different (nickel alloy vs stainless steel) the aging effect of reduction of heat transfer due to fouling would be expected to manifest itself in similar ways for both materials.

Request:

1) Provide an inspection activity to confirm effectiveness of the Water Chemistry Program to mitigate the aging effect of loss of heat transfer due to fouling in these components.

or

2) Provide a technical justification explaining why such a confirmation is not needed.

NSPM Response to RAI 3.1.2-5-01

<u>Part 1</u>

PINGP will provide an inspection activity to confirm effectiveness of the Water Chemistry Program to mitigate the aging effect of loss of heat transfer due to fouling in these components in a Treated Water (External) environment.

For the environment Treated Water (Ext), which is demineralized water, the LRA is being revised to add the One-Time Inspection Program to provide for the verification of the effectiveness of Water Chemistry to mitigate the aging effect of loss of heat transfer due to fouling in steam generator U-Tubes. The One-Time Inspection Program includes measures to verify the effectiveness of the Water Chemistry Program to mitigate aging effects including: (a) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience;

(b) identification of inspection locations in the system, component, or structure based on the aging effect; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect that is being examined; and (d) evaluation of the need for follow-up examination if degradation is identified that could jeopardize an intended function prior to the end of the period of extended operation.

Therefore, the following LRA revisions are made:

In LRA Table 3.1.2-5 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator System - Summary of Aging Management Evaluation, on page 3.1-128, in the line item for U-tubes (Unit 1) in a Treated Water (Ext) environment, for the Aging Effect Heat Transfer Degradation - Fouling, the One-Time Inspection Program is added, as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Line Item	Table 1	Notes
U-Tubes (Unit 1)	Heat Transfer	Nickel Alloy	Treated Water (Ext)	Heat Transfer Degradation - Fouling	Water Chemistry Program			H
					One-Time Inspection Program			H

In LRA Table 3.1.2-5 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator System - Summary of Aging Management Evaluation, on page 3.1-129, in the line item for U-tubes (Unit 2) in a Treated Water (Ext) environment, for the Aging Effect Heat Transfer Degradation - Fouling, the One-Time Inspection Program is added, as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Line Item	Table 1	Notes
U-Tubes (Unit 2)	Heat Transfer	Nickel Alloy	Treated Water (Ext)	Heat Transfer Degradation - Fouling	Water Chemistry Program			H
					One-Time Inspection Program			H

<u>Part 2</u>

An inspection activity to confirm effectiveness of the Water Chemistry Program to mitigate the aging effect of loss of heat transfer due to fouling in a Treated Water (Internal) environment is not required based on the following technical justification:

NUREG-1801, Volume 2, line item V.A-16, is for heat exchanger tubes exposed to treated water.

Per NUREG-1801, Section IX.D, Selected Definitions & Use of Terms for Describing and Standardizing – Environments, “Treated water is demineralized water, which is the base water for all clean systems. Depending on the system, this demineralized water may require additional processing. Treated water could be deaerated and include corrosion inhibitors, biocides, or some combination of these treatments. Unlike the PWR reactor coolant environment (treated borated water), the BWR reactor coolant environment (i.e., treated water) does not contain boron, a recognized corrosion inhibitor.”

The Treated Water (Internal) environment on the U-Tubes is reactor coolant and not demineralized water. As stated above boron is a recognized corrosion inhibitor. In accordance with NUREG-1800, Table 3.1-1, ID 81 and 83 (NUREG-1801 Line Items IV.D1-6 and IV.C2-15), the Water Chemistry Program alone is adequate for managing loss of material and cracking of nickel alloy exposed to reactor coolant.

In accordance with NUREG-1801, Section XI.M2, Water Chemistry, Element 4, Detection of Aging Effects, “This is a mitigation program and does not provide for detection of any aging effects. In certain cases as identified in the GALL Report, inspection of select components is to be undertaken to verify the effectiveness of the chemistry control program and to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period of operation.” NUREG-1801 Line Items IV.D1-6 and IV.C2-15 and Table 1, IDs 81 and 83, do not require verification of the effectiveness of the water chemistry control program in a reactor coolant environment.

NUREG-1801, Section IX.F, Selected Definitions & Use of Terms for Describing and Standardizing Aging Mechanisms, describes fouling as, “An accumulation of deposits. This term includes accumulation and growth of aquatic organisms on a submerged metal surface and also includes the accumulation of deposits, usually inorganic, on heat exchanger tubing. Biofouling, as a subset of fouling, can be caused by either macro-organisms (such as barnacles, Asian clams, zebra mussels, and others found in fresh and salt water) or micro-organisms, e.g., algae. Fouling can also be categorized as particulate fouling (sediment, silt, dust, and corrosion products), marine biofouling, or macrofouling, e.g., peeled coatings, debris, etc.” Fouling of the Steam Generator U-Tubes on the reactor coolant side would only occur through the buildup of corrosion products. Since NUREG-1800 and NUREG-1801 allow the use of the Water Chemistry Program alone for corrosion control in a reactor coolant environment, then a verification of the effectiveness of the Water Chemistry Program to mitigate the aging effect of loss of heat transfer due to fouling would not be required.

RAI 3.1.2.2.7-01

LRA Section: Section 3.1.2.2.7.1, page 3.1.12; Table 3.1.1, item 3.1.1-23, page 3.1-22; Table 3.1.2-4, pages 3.1-95 and -99.

Background: SRP-LR Section 3.1.2.2.7.1 states that cracking due to SCC could occur in the PWR stainless steel reactor vessel flange leak detection lines and the bottom mounted instrument guide tubes exposed to reactor coolant. GALL Report items IV.A.2-1 (bottom-mounted guide tube) and IV.A.2-5 (vessel flange leak detection line) recommend that a plant-specific AMP be evaluated. PINGP proposes to manage the aging effect of cracking due to SCC in these components with the Water Chemistry Program, alone.

Issue: SRP-LR provides acceptance criteria for plant-specific AMPs in Appendix A.1, Aging Management Review – Generic (Branch Technical Position RLSB-1), which is referenced in SRP-SR, Section 3.1.2.2.7.1.

Branch Technical Position RLSB-1 states that a plant-specific aging management program should include a “detection of aging effects” program element. PINGP’s Water Chemistry Program is a mitigation program and does not include detection of aging effects. Therefore, PINGP’s Water Chemistry Program, alone, does not meet the requirements for a plant-specific AMP under the criteria of Branch Technical Position RLSB-1.

Request:

1) Provide a plant-specific AMP or combination of existing AMPs that include a “detection of aging effect” program element for managing the aging effect of cracking due to SCC in the stainless steel reactor vessel flange leak detection line and in bottom mounted instrument guide tubes; and

2) Describe what examination techniques will be used to detect (or confirm the absence of) the aging effect of cracking due to SSC in the vessel flange leak detection line and the bottom mounted instrument guide tubes, or

3) Provide both a technical justification and a regulatory justification as to why confirmation of water chemistry effectiveness is not needed and why a “detection of aging effect” program element is not required.

NSPM Response to RAI 3.1.2.2.7-01

Part 1

The PINGP LRA is hereby revised to assign the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program to manage cracking due to SCC in addition to the Water Chemistry Program for the stainless steel Bottom Mounted Instrumentation (BMI) Guide Tubes & Fittings exposed to treated water. In addition, the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, and the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program are assigned to manage cracking due to SCC in addition to the Water Chemistry Program for the stainless steel Flange O-Ring Leak Detection Tubes.

Therefore, the following revisions are made to the LRA:

In LRA Table 3.1.1, Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Vessel, Internals, and Reactor Coolant System, on page 3.1-22, Line item 3.1.1-23 is revised to appear as follows:

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-23	Stainless steel reactor vessel closure head flange leak detection line and bottom-mounted instrument guide tubes	Cracking due to stress corrosion cracking	A plant-specific aging Management program is to be evaluated.	Yes, plant specific	The plant-specific AMPs that manage cracking due to stress corrosion cracking of the stainless steel reactor vessel closure head flange leak detection line are the Water Chemistry Program, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, and the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program. The plant-specific AMPs that manage cracking due to stress corrosion cracking of the stainless steel bottom-mounted instrument guide tubes are the Water Chemistry Program and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. Further evaluation is documented in Section 3.1.2.2.7.1.

In LRA Table 3.1.2-4, Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel System - Summary of Aging Management Evaluation, on page 3.1-95, the line item for Bottom Mounted Instrumentation (BMI) Guide Tubes & Fittings in Treated Water (Int), for the Aging Effect Cracking - SCC/IGA, is revised to add the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Line Item	Table 1	Notes
Bottom Mounted Instrumentation (BMI) Guide Tubes & Fittings	Pressure Boundary	Stainless Steel	Treated Water (Int)	Cracking - SCC/IGA	Water Chemistry Program	IV.A2-1	3.1.1-23	E
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program	IV.A2-1	3.1.1-23	E

In LRA Table 3.1.2-4, Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel System - Summary of Aging Management Evaluation, on page 3.1-99, the line item for Flange O-Ring Leak Detection Tubes in Treated Water (Int), for the Aging Effect Cracking - SCC/IGA, is revised to add the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program as follows:

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Line Item	Table 1	Notes
Flange O-Ring Leak Detection Tubes	Pressure Boundary	Stainless Steel	Treated Water (Int)	Cracking - SCC/IGA	Water Chemistry Program	IV.A2-5	3.1.1-23	E
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program	IV.A2-5	3.1.1-23	E
					One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program	IV.A2-5	3.1.1-23	E

In LRA Section 3.1.2.2.7 on page 3.1-12, Part 1 is revised in its entirety to read as follows:

1. Cracking due to stress corrosion cracking could occur for the stainless steel reactor vessel closure head flange leak detection line. This aging effect is managed with the Water Chemistry Program, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, and the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program. Cracking due to stress corrosion cracking could occur for stainless steel reactor vessel bottom-mounted instrument guide tubes. This aging effect is managed with the Water Chemistry Program and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program.

   The Water Chemistry Program includes specifications for chemical species, sampling and analysis frequencies, and corrective actions for control of water chemistry. The program controls concentrations of known detrimental chemical species such as chlorides, fluorides, sulfates and dissolved oxygen below the levels known to cause degradation. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program includes periodic visual, surface, and/or volumetric examination of Class 1, 2, and 3 pressure-retaining components, their welded integral attachments, and bolting. Leakage tests are periodically performed on Class 1, 2, and 3 pressure-retaining components. The program also provides component repair and replacement requirements in accordance with ASME Section XI. The One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program inspects for the presence of cracking by performing one-time volumetric examinations on a sample of butt welds in Class 1 piping (including pipes, fittings, and branch connections) less than 4 inch nominal pipe size (NPS 4). The one-time inspections are performed at locations that are determined to be potentially susceptible to cracking. These programs assure the intended function of affected components will be maintained during the period of extended operation.

<u>Part 2</u>

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program manages cracking due to SCC for the Bottom Mounted Instrumentation (BMI) Guide Tubes & Fittings. The BMI Guide Tubes & Fittings receive a VT-2 visual inspection in accordance with ASME Section XI, Table IWB-2500-1, Examination Category B-P.

The One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program monitors for aging effects by performing one-time volumetric examinations of Class 1 small-bore piping to detect cracking at butt weld locations that are determined to be potentially susceptible to cracking using the methodology of the site specific NRC approved Risk Informed Inservice Inspection Program.

<u>Part 3</u>

Response not required.

RAI 3.2.2.2.3.6-01

LRA Section: Section 3.2.2.2.3.6, pages 3.2-7 and 3.2-8

Background: SRP-SR Section 3.2.2.2.3.6 states that loss of material due to pitting and crevice corrosion could occur for stainless steel piping, piping components, piping elements, and tanks exposed to internal condensation. LRA Section 3.2.2.2.3.6 and Table 3.2.1, item 3.2.1-08, both state that the AMR result in the GALL Report is not applicable because PINGP does not have stainless steel piping and piping components exposed to condensation in GALL Report Chapter V [engineered safety features] systems.

Issue: The statement in LRA Section 3.2.2.2.3.6 does not address stainless steel tanks, which are included in the list of components that may be in an environment of internal condensation in SRP-SR Section 3.2.2.2.3.6. Also, it is not clear how PINGP determined that stainless steel piping in the containment spray is not exposed to internal condensation.

Request:

1) Provide the basis for the statement in the LRA that there are no stainless steel piping and piping components exposed to condensation in GALL Report Chapter V systems, specifically addressing stainless steel piping in the containment spray system (GALL Report Volume 2, item V.A-26) and stainless steel tanks in the safety injection system (GALL Report Volume 2, item V.D1-29).

NSPM Response to RAI 3.2.2.2.3.6-01

The Containment Spray System spray nozzles and selected piping were assigned an internal environment of Primary Containment Air (Int). These components are completely within the Auxiliary Building and Containment. The Auxiliary Building indoor areas are protected from weather and have an ambient temperature range between $60^{o}F$ to $125^{o}F$. The Containment indoor areas are protected from weather and have an ambient temperature range between $50^{o}F$ and $120^{o}F$. The internal air/gas environment of the Containment Spray System piping and nozzles is at the same temperature as the surrounding room temperature such that condensation is not expected.

The partially filled stainless steel tanks in the Safety Injection System are the Refueling Water Storage Tanks and the Reactor Coolant Safety Injection Accumulators. These tanks are completely contained within the Auxiliary Building and Containment respectively. The Auxiliary Building indoor areas are protected from weather and have an ambient temperature range between $60^{o}F$ to $125^{o}F$. The Containment indoor areas are protected from weather and have an ambient temperature range between $50^{o}F$ and $120^{o}F$. The internal fluid environment and internal air/gas environment of these tanks are at the same temperature as the surrounding room temperature such that condensation is not expected. If a portion of a component was exposed to fluid, then typically the component was conservatively assumed to be fully exposed to the fluid environment for performing the Aging Management Evaluations.

The PINGP Systems in GALL Chapter V were shown to have internal environments of Lubricating Oil (Int), Nitrogen Gas (Int), Plant Indoor Air - Uncontrolled (Int), Primary Containment Air (Int), and Treated Water (Int). The internal environment of "condensation" was not utilized and consequently LRA Section 3.2.2.2.3.6 and Table 3.2.1, item 3.2.1-08, are both correct in stating that the AMR result in the GALL Report is not applicable.

RAI 3.2.2.2.4.2-01

LRA Section: Section 3.2.2.2.4.2, page 3.2-8; Table 3.2.1, item 3.2.1-10, page 3.2.13.

Background: The SRP-LR in Section 3.2.2.2.4.2 states that reduction in heat transfer due to fouling could occur for stainless steel heat exchanger tubes exposed to treated water and recommends that effectiveness of water chemistry control to mitigate this aging effect should be confirmed to ensure that reduction of heat transfer is not occurring and that the component's intended function will be maintained during the period of extended operation.

Issue: The AMR results presented in the LRA state that the Water Chemistry Program, alone, is adequate to control this aging effect and that verification of Water Chemistry Program effectiveness is not needed. The discussions in LRA Section 3.2.2.2.4.2 and item 3.2.1-10 refer to GALL Report line items 3.2.1-48 and 3.2.1-49 where the Water Chemistry Program, alone, is recommended to manage the aging effects of cracking due to SCC and loss of material due to pitting and crevice corrosion for stainless steel piping and piping components in a borated treated water environment.

Request:

1) Identify the heat exchangers in the engineered safety features system that are the subject of this AMR.
2) State whether these heat exchangers are periodically examined under an existing plant program to the extent that indications of fouling in the heat exchanger tubes can be detected.
3) Explain why reference to AMR results where the aging effects are cracking and loss of material are used to support not monitoring for the aging effect of reduction in heat transfer due to fouling.
4) Provide a technical justification for not performing a one-time inspection to confirm Water Chemistry Program Effectiveness, as recommended in the GALL Report for this component, material, environment and aging effect combination.

NSPM Response to RAI 3.2.2.2.4.2-01

Part 1

The heat exchangers in the engineered safety features system that are the subject of this AMR are as follows:

Reactor Coolant Pump Thermal Barrier Heat Exchanger
Containment Spray Pump Seal Cooler Tubing
Residual Heat Removal Heat Exchanger Tubing
Residual Heat Removal Pump Seal Water Cooler Tubing
Safety Injection Pump Seal Water Cooler Tubing

Part 2

There are no requirements to examine these heat exchangers.

Parts 3 & 4

SRP Subsection 3.2.2.2.4.2, Table 3.2-1, ID 10, EP-34 (NUREG-1801, Volume 2, line item V.A-16) is for stainless steel heat exchanger tubes exposed to treated water.

Per NUREG-1801, Section IX.D, Selected Definitions & Use of Terms for Describing and Standardizing – Environments: “Treated water is demineralized water, which is the base water for all clean systems. Depending on the system, this demineralized water may require additional processing. Treated water could be deaerated and include corrosion inhibitors, biocides, or some combination of these treatments. Unlike the PWR reactor coolant environment (treated borated water), the BWR reactor coolant environment (i.e., treated water) does not contain boron, a recognized corrosion inhibitor.”

The Treated Water (Int) environment in the heat exchanger tubes is treated borated water and not demineralized water. As stated above boron is a recognized corrosion inhibitor. In accordance with NUREG-1800, Table 3.2-1, IDs 48 and 49, (NUREG-1801 Line Items V.A-28, V.D1-31, V.A-27, and V.D1-30), the Water Chemistry Program alone is adequate for managing loss of material and cracking of stainless steel exposed to treated borated water.

In accordance with NUREG-1801, XI.M2 Water Chemistry, Element 4, Detection of Aging Effects, “This is a mitigation program and does not provide for detection of any aging effects. In certain cases as identified in the GALL Report, inspection of select components is to be undertaken to verify the effectiveness of the chemistry control program and to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period of operation.” NUREG-1801 Line Items V.A-28, V.D1-31, V.A-27, and V.D1-30 and NUREG-1801, Table 2, IDs 48 and 49 do not require verification of the effectiveness of the water chemistry control program.

NUREG-1801, Section IX.F, Selected Definitions & Use of Terms for Describing and Standardizing Aging Mechanisms, describes fouling as “An accumulation of deposits. This term includes accumulation and growth of aquatic organisms on a submerged metal surface and also includes the accumulation of deposits, usually inorganic, on heat exchanger tubing. Biofouling, as a subset of fouling, can be caused by either macro-organisms (such as barnacles, Asian clams, zebra mussels, and others found in fresh and salt water) or micro-organisms, e.g., algae. Fouling can also be categorized as particulate fouling (sediment, silt, dust, and corrosion products), marine biofouling, or macrofouling, e.g., peeled coatings, debris, etc.” Fouling of the heat exchanger tubes on the treated borated water side would only occur through the buildup of corrosion products. Since NUREG-1800 and NUREG-1801 allow the use of the Water Chemistry Program alone for corrosion control in treated borated water environment, then a verification of the effectiveness of the Water Chemistry Program to mitigate the aging effect of reduction of heat transfer due to fouling would not be required. In addition, NUREG-1801 does not include reduction in heat transfer due to fouling as an applicable aging effect in a treated borated water environment.

RAI 3.3.1-51-01

LRA Section: Table 3.3.1, item number 3.3.1-51, page 3.3-54; Table 3.3.2-3; Table 3.3.2-5; Table 3.3.2-8; Table 3.3.2-9; Table 3.3.2-11; Table 3.3.2-13; Table 3.3.2-20

Background: The GALL Report indicates that the aging effect/mechanism for this Table 3.3.1, item number 3.3.1-51 is loss of material due to pitting, crevice and galvanic corrosion. The component is copper alloy piping, piping components, piping elements and heat exchanger elements exposed to closed cycle cooling water, and galvanic corrosion is normally an aging mechanism associated with copper or copper alloy components.

Issue: Review of the AMR result lines in the 3.X.2 tables that refer to item number 3.3.1-51 did not find any AMR results that list galvanic corrosion as an aging mechanism.

Request:

1) Why is the aging mechanism of galvanic corrosion not included for these copper alloy components?

NSPM Response to RAI 3.3.1-51-01

Analysis tools provided by Electric Power Research Institute (EPRI) reports, Westinghouse generic topical reports and other industry guidelines were the primary means to identify and evaluate aging effects. Operating experience, both industry and plant-specific, was also used to identify aging effects. The GALL report was used to identify aging management programs which were determined by the NRC to be acceptable programs to manage the identified aging effects.

Copper and Copper Alloys are in the middle of the galvanic series and will preferentially corrode when coupled with more cathodic metals (such as stainless steel). However, the rate of corrosion is expected to be low due to the small electrochemical potential difference. Operating experience at PINGP has not identified galvanic corrosion concerns with Copper and Copper Alloys. Therefore galvanic corrosion was not considered applicable to Copper and Copper alloys.

RAI 3.3.1-76-01

LRA Section: Table 3.3.1, item number 3.3.1-76, page 3.3-60; and various lines referring to 3.3.1-76 in Table 3.3.2-3, Table 3.3.2-5, Table 3.3.2-6, Table 3.3.2-7, Table 3.3.2-8, Table 3.3.2-20, Table 3.3.2-21

Background: The discussion column in LRA item number 3.3.1-76 states that the AMR results are consistent with the GALL Report and that the aging effect is managed by the Open-Cycle Cooling Water System Program. Review of the 3.X.2 tables listed above finds multiple AMR result lines referring to item number 3.3.1-76 where the AMP is the

Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program and generic note E is cited, indicating that the line is consistent with the GALL Report for component, material, environment combination, but a different AMP is used.

Issue: The statement in the discussion column says the aging effect is managed by the Open-Cycle Cooling Water System Program. This is either incorrect or misleading since the Open-Cycle Cooling Water System Program is used to manage the aging effect for only some of the AMR result lines, and the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is used to manage the aging effect in other ARM result lines.

Request:

1) Explain why the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, rather than the Open-Cycle Cooling Water System Program, is used for some of the AMR result lines.

2) Revise the discussion in LRA Table 3.3.1, item 3.3.1-76, to clarify that two different aging management programs are used, or justify why the LRA does not need to be revised.

NSPM Response to RAI 3.3.1-76-01

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is used in lieu of the Open-Cycle Cooling Water System Program where the components managed are not exposed to an Open-Cycle Cooling Water environment. For LRA Table 3.3.1, line item 3.3.1-76, the Internal Surfaces in Miscellaneous Piping and Ducting Components Program is credited for managing aging effects for components exposed to waste water or potable water environments in the Control Room and Miscellaneous Area Ventilation (Table 3.3.2-5), Cooling Water (Table 3.3.2-6), Diesel Generator and Screen house Ventilation (Table 3.3.2-7), Diesel Generator and Support (Table 3.3.2-8), Waste Disposal (Table 3.3.2-20) and Water Treatment (Table 3.3.2-21) Systems. The Component Cooling Water System (Table 3.3.2-3) does not reference line item 3.3.1-76.

In LRA Table 3.3.1, line item number 3.3.1-76, the discussion column should also reference the Internal Surfaces in Miscellaneous Piping and Ducting Components Program. Accordingly, the discussion column entry for LRA Table 3.3.1, line item number 3.3.1-76 on page 3.3-60, is revised to read:

> "Consistent with NUREG-1801. This aging effect is managed with the Open-Cycle Cooling Water System Program. In some cases, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is credited in lieu of the Open-Cycle Cooling Water System Program."

RAI 3.3.1-77-01

LRA Section: Table 3.3.1, item number 3.3.1-76, page 3.3-60; and various lines referring to 3.3.1-77 in Table 3.3.2-3, Table 3.3.2-5, Table 3.3.2-6, Table 3.3.2-8, Table 3.3.2-17, and Table 3.3.2-20

Background: The discussion column in LRA item number 3.3.1-77 states that the AMR results are consistent with the GALL Report and that the aging effect is managed by the Open-Cycle Cooling Water System Program. It also states that in some cases, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program or the Fire water System Program is credited in lieu of the Open-Cycle Cooling Water System Program. Review of the 3.X.2 tables listed above finds multiple AMR result lines referring to item number 3.3.1-77. However, none of these AMR result lines identify the Fire Water System Program as the AMP credited to manage the aging effect in these components.

Issue: The statement in the discussion column says in some instances the Fire Water System Program is credited in lieu of the Open-Cycle Cooling Water System Program appears to be incorrect.

Request:

1) Identify the location in the LRA of AMR result lines that refer to item number 3.3.1-77 where the Fire Water System Program is credited to provide aging management, or correct the description in the discussion column for LRA Table 3.3.1, item number 3.3.1-77, saying that the Fire Water System Program is credited.
2) Explain why the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program or the Fire water System Program (if actually used) are credited in lieu of the Open-Cycle Cooling Water System Program for some of these AMR result lines.

NSPM Response to RAI 3.3.1-77-01

In LRA Table 3.3.1, on page 3.3-60, line item number 3.3.1-77, reference to the Fire Water System Program for providing aging management is incorrect. The reference to the Fire Water System should be deleted. Accordingly, the discussion column entry for LRA Table 3.3.1, line item number 3.3.1-77 is revised to read:

> "Consistent with NUREG-1801. This aging effect is managed with the Open-Cycle Cooling Water System Program. In some cases, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is credited in lieu of the Open-Cycle Cooling Water System Program."

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is used in lieu of the Open-Cycle Cooling Water System Program where the components managed are not exposed to an Open-Cycle Cooling Water environment.

For LRA Table 3.3.1, line item 3.3.1-77, the Internal Surfaces in Miscellaneous Piping and Ducting Components Program is credited for managing aging effects for components exposed to a waste water environment in the Waste Disposal System (Table 3.3.2-20).

RAI 3.3.1-78-01

LRA Section: Table 3.3.1, item number 3.3.1-78, page 3.3-60

Background: The discussion column in LRA item number 3.3.1-78 states that this line was not used at PINGP and says, “See LRA line item 3.3.1-79 for further discussion.”

Issue: It does appear that the AMR results for LRA item number 3.3.1-78 could be included as a subset of the AMR results in LRA item number 3.3.1-79 based on similarity of component, material, environment and aging effect. However, there is no mention of LRA line item 3.3.1-78 in the discussion column of LRA line item 3.3.1-79.

Request:

1) Revise the statement in LRA item number 3.3.1-78, or add an appropriate discussion of 3.3.1-78 into the discussion column of LRA item number 3.3.1-79

NSPM Response to RAI 3.3.1-78-01

In LRA Table 3.3.1, the discussion column in LRA Item number 3.3.1-78 is intended to provide a convenient link to clarify that the material, environment, aging effect combination in line 3.3.1-78 is applicable to PINGP although it is evaluated under a different line. Line 3.3.1-78 is not intended to be included by reference in line 3.3.1-79. Line 3.3.1-78 is not used at PINGP, and no additional detail is required in line 3.3.1-79 discussion column.

RAI 3.3.2-08-01

In LRA Tables 3.3.2-08, 3.3.2-09, 3.4.2-03, 3.4.2-04, flex connections and expansion joints that are fabricated from rubber and natural rubber, exposed to an internal environment of treated or raw water and subject to the aging effects of change in material properties and cracking referenced the applicable plant-specific note 323 or 423 which states in part, that the external environment is the same as the internal environment. Please clarify if the internal environment for these AMR line items is identical to the external environment or if the external environment is more aggressive. If the latter is the case, identify the external environment for these components. Please consider in your response the impact RAI B2.1.14 may have, and if the appropriate program to manage the effects of aging for non-metallic components will be capable of being credited so that the external surface may be representative of the internal surfaces. If not, provide an appropriate program that is capable of managing the aging of the internal surfaces for non-metallic components.

NSPM Response to RAI 3.3.2-08-01

Notes 323 and 423 state, "The External Surfaces Monitoring Program is credited with managing aging effects of internal surfaces where the external surfaces are subject to the same environment or stressor as the internal surfaces such that the external condition is representative of the internal condition." The external environment (Plant Indoor Air – Uncontrolled) for these line items is not identical to the internal environment (Raw Water or Treated Water); however the external thermal exposure stressor (i.e., temperature), which may result in cracking and change in material properties, is the same as the internal thermal exposure stressor (i.e., temperature). In addition, the external environment, Plant Indoor Air – Uncontrolled, is more aggressive related to the same aging effects, cracking and change in material properties, due to the additional aging mechanisms of ultraviolet exposure and ozone exposure. Therefore, the external surface condition is representative of the internal surface condition and the External Surfaces Monitoring Program is credited with detection of the aging effects on the external surfaces prior to aging effects on the internal surfaces resulting in a loss of intended function. The External Surfaces Monitoring Program described in Section B2.1.14 of the LRA is an appropriate program for managing aging of these non-metallic components. For additional discussion, see the response to RAI AMP-B2.1.14-1 in NSPM letter dated December 5, 2008.

RAI 3.3.2-9-01

LRA Section: Table 3.3.2-9, page 3.3-206

Background: LRA Table 3.3.2-9 shows AMR results for copper alloy piping/fittings in the fire protection system in a fuel oil environment with an aging effect of cracking due to SCC/IGA. Three AMPs are shown as applicable for these components: 1) Fire Protection Program; 2) Fuel Oil Chemistry Program; and 3) One-Time Inspection Program. Note H is used for these AMR result lines, and there is no reference to GALL Report Volume 2 line items.

Issue: Because these results are not in the GALL Report, there are no GALL Report Volume 2 line item references to link the three AMPs. Consequently, there is no way for a reviewer to determine whether the aging effect is managed by all three of the AMPs together, or whether for some components it is managed by a combination of only two programs. For example, the Fuel Oil Chemistry Program and the One-Time Inspection Program might be credited for some components; while for other components the Fire Protection Program and the One-Time Inspection Program might be credited; and for still other components the Fuel Oil Chemistry Program and the Fire Protection Program might be credited.

Request:

1) For all components in these AMR result lines, is the aging effect managed by all three AMPs together?
2) If all components in these AMR result lines are not managed by all three AMPs together, then identify what combinations of AMPs are used, and for what set of components each combination of AMPs is credited.
3) Is Fuel Oil Chemistry Program credited for all components in these AMR results lines?
4) Are there any components for which Fuel Oil Chemistry Program, alone, is credited?
5) For components where the Fire Protection Program is credited, is the Fire Protection Program credited to provide both mitigation and detection of the aging effect? If credited to provide detection of the aging effect, then explain how the Fire Protection Program detects the aging effect of cracking due to SCC/IGA.

NSPM Response to RAI 3.3.2-9-01

Parts 1 & 2

For all copper alloy piping/fitting components addressed in these Aging Management Review line items, the aging effect of cracking due to SCC/IGA is managed by a combination of all three Aging Management Programs: Fire Protection Program, Fuel Oil Chemistry Program, and One-Time Inspection Program.

Parts 3 & 4

For all copper alloy piping/fitting components addressed in these Aging Management Review line items, the aging effect of cracking due to SCC/IGA is managed by a combination of all three Aging Management Programs: Fire Protection Program, Fuel Oil Chemistry Program, and One-Time Inspection Program.

Part 5

The Fire Protection Program does not provide for mitigation of the aging effect but is credited with providing detection of the aging effect. The combination of aging management activities performed in accordance with the requirements of the Fire Protection, Fuel Oil Chemistry, and One-Time Inspection Programs provide reasonable assurance that cracking of the diesel-driven fire pump fuel supply line will be adequately managed for the period of extended operation. For additional discussion, see the response to RAI AMP-B2.1.15-1 in NSPM letter dated December 5, 2008.

RAI 3.3.2-13-01

LRA Section: Table 3.3.2-13, pages 3.3-259, -263, -265, -266, and -269.

Background: On the pages listed above, there are AMR result lines for various carbon steel piping components in a treated water environment where the aging effect is identified as cracking due to stress corrosion cracking and the AMP proposed to manage the aging effect is the Closed-Cycle Cooling Water Program, alone. These AMR result lines cite generic note H, (Aging effect not in NUREG-1801 for this component, material, and environment combination not applicable.)

Issue: Cracking due to SCC is not normally associated with carbon steel components. In addition, the Closed-Cycle Cooling Water System Program (B2.1.9) does not include any examination techniques applicable for carbon steel components that are capable of detecting cracks due to SCC. However, the "detection of aging effects" program element for GALL AMP XI.M21, Closed-Cycle Cooling Water System, states that inspection and testing should assure the detection of corrosion or SCC before the loss of intended function.

Request:

1) What is the basis for expecting that cracks due to SCC may occur in the carbon steel piping components (pipe, valves, pumps, tanks, heat exchanger components) exposed to treated water in the plant sample system? Cite any plant-specific or industry operating experience or information that supports occurrence of this aging effect in carbon steel piping components.
2) Provide an examination technique for these components that is capable of detecting cracks due to SCC, or provide a justification as to why examination for cracks is not needed to ensure adequate aging management for these components.

NSPM Response to RAI 3.3.2-13-01

<u>Part 1</u>

The PINGP operating experience review for the Plant Sample System identified microbiological bacteria in the Cold Lab Sample Chiller. On a routine quarterly sample of the Cold Lab Sample Chiller, aerobic bacteria counts showed 10,000 bact/ml. This was confirmed by a backup sample. This was the third time in a year that bacteria counts were elevated. On each occasion additions of biocide were made, and the bacteria would become evident again after a few months. On the final occasion the nitrites in the corrosion inhibitor were totally consumed. On Sept. 7, 2001, the Cold Lab Sample Chiller was drained, flushed, and refilled with an approximately 50/50 mix of Fleet-charge Antifreeze which also contains a nitrite-based corrosion inhibitor.

In accordance with EPRI 1010639, Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 4, Final Report, January 2006, stress corrosion cracking (SCC) of carbon and low-alloy steels is considered an applicable aging mechanism in treated water systems in which a nitrite corrosion inhibitor is used, there is a potential for MIC contamination, pH is less than 10.5, and temperature is less than 210°F. Due to this plant specific operating experience, cracking due to SCC was assumed in the Plant Sample System hot and cold lab sample chiller components made of carbon steel.

Part 2

The Closed-Cycle Cooling Water System Program is both a preventive and condition monitoring program that is based on the Electric Power Research Institute (EPRI) "Closed Cooling Water Chemistry Guideline", TR-107396, Revision 1. The program includes preventive measures to minimize corrosion, heat transfer degradation, and stress corrosion cracking (SCC); and testing and inspection to monitor the effects of corrosion, heat transfer degradation, and SCC on the intended functions of the components. The preventive measures consist of maintaining the system corrosion inhibitor concentrations within the specified limits by periodic testing. Testing is performed to verify key chemistry parameters and to measure impurities, conductivity and microbiological growth. Inspections are performed to identify corrosion, fouling and SCC that may be present.

Periodic visual inspections, performed in conjunction with scheduled maintenance activities, are sufficient to detect loss of material due to corrosion and heat transfer degradation due to fouling. Inspections for stress corrosion cracking will be performed by visual examination with a magnified resolution (i.e., enhanced visual) as described in 10 CFR 50.55a(b)(2)(xxi)(A) or with ultrasonic methods.

In response to this RAI, and to clarify the scope of Closed Cycle Cooling Water system inspections, the program enhancement described in Section B2.1.9 of the PINGP LRA is revised as follows.

In LRA Section B2.1.9 on page B-28, delete the existing enhancement and replace it in its entirety with the following:

- Monitoring and Trending

  The program will be enhanced to include periodic inspection of accessible surfaces of components serviced by closed-cycle cooling water when the systems or components are opened during scheduled maintenance or surveillance activities. Inspections are performed to identify the presence of aging effects and to confirm the effectiveness of the chemistry controls. Visual inspection of component internals will be used to detect loss of material and heat transfer degradation. Enhanced visual or volumetric examination techniques will be used to detect cracking.

To reflect this change, Preliminary License Renewal Commitment No. 6 included in the LRA transmittal letter dated April 11, 2008, is revised to read as follows:

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
6	The Closed-Cycle Cooling Water System Program will be enhanced to include periodic inspection of accessible surfaces of components serviced by closed-cycle cooling water when the systems or components are opened during scheduled maintenance or surveillance activities. Inspections are performed to identify the presence of aging effects and to confirm the effectiveness of the chemistry controls. Visual inspection of component internals will be used to detect loss of material and heat transfer degradation. Enhanced visual or volumetric examination techniques will be used to detect cracking.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.9

RAI 3.3.2-20-01

In LRA Table 3.3.2-20, several AMR Line Items reference the following:

- Table 1 item 3.3.1-77 and GALL Report Volume 2 line item VII.C1-5
- Table 1 item 3.4.1-33 and GALL Report Volume 2 line item VIII.E-3
- Table 1 item 3.3.1-82 and GALL Report Volume 2 line item VII.C1-3

These AMR line items credit the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The staff noted that the environment for some of these line items as described above is raw water on the external surface. Please clarify how a visual inspection of the internal surfaces of the heat exchanger components and/or tubes will be capable of determining the condition of the surfaces exposed to the raw water on the external surface of these heat exchanger components and/or tubes.

NSPM Response to RAI 3.3.2-20-01

The components which credit the Internal Surfaces and Miscellaneous Piping and Ducting Components Program for a raw water external environment are heat exchanger tubes and tubesheets (heat exchanger components). Internal and external environments are assigned to heat exchanger tubes and tubesheets to evaluate the environment to which each side is exposed. The external sides of heat exchanger tubes and tubesheets are physically internal to the heat exchangers, and therefore the Internal Surfaces and Miscellaneous Piping and Ducting Components Program is appropriate for management of aging effects. The internal environments, which are also internal to the heat exchangers, are evaluated under separate lines.

RAI 3.3.2-20-02

In LRA Table 3.3.2-20 and 3.4.2-08, several AMR line items reference the following:

- Table 1 item 3.3.1-77 and GALL Report Volume 2 line item VII.C1-5
- Table 1 item 3.4.1-33 and GALL Report Volume 2 line item VIII.E-3
- Table 1 item 3.4.1-8 and GALL Report Volume 2 line item VIII.G-36
- Table 1 item 3.4.1-32 and GALL Report Volume 2 line item VIII.A-4

These AMR line items credit the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, which performs a periodic visual inspection of the components. Please justify how a visual inspection alone, is capable of detecting the aging effect of loss of material in heat exchanger components and tubes in those regions that are not directly visible (e.x. the bend of a heat exchanger tube) or provide an appropriate inspection technique or program that will be capable of detecting the aging effect of loss of material for those regions that are not directly accessible for a visual inspection.

NSPM Response to RAI 3.3.2-20-02

In LRA Table 3.3.2-20, on pages 3.3-311 through 3.3-315, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is credited for managing Loss of Material in heat exchanger components and tubes. These line items consist of heat exchanger shells, tubesheets, channelheads and tubes. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program performs visual inspections of internal surfaces of mechanical components during scheduled preventive and corrective maintenance activities, or during other routinely scheduled tasks such as surveillance procedures, when internal surfaces are made accessible for inspections. Inspection locations will be chosen to include conditions susceptible to the aging effects of concern. Visual inspections are expected to detect the presence of corrosion and cracking of accessible internal surfaces of metallic components. Aging effects will be detected through the presence of indications such as rust, discoloration, scale/deposits, pitting, and surface discontinuities. Implementation of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program provides a reasonable assurance that aging effects will be managed such that the heat exchanger components will continue to perform their intended function(s) during the period of extended operation.

In LRA Table 3.4.2-8, on pages 3.4-126 and 3.4-127, and on page 3.4-131, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is credited for managing Loss of Material in heat exchanger components and tubes. These heat exchanger components and tubes are supplied by the Cooling Water System and should not have credited the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program for aging management. The appropriate aging management program is the Open-Cycle Cooling Water System

Program. The Open-Cycle Cooling Water System Program conducts eddy current testing of these heat exchanger tubes to detect loss of material.

Therefore, the following changes are made to Table 3.4.2-8 of the LRA:

In Table 3.4.2-8 on pages 3.4-126 and -127, for Heat Exchanger Components exposed to Raw Water (Int), the lines aligned to Table 1, Item 3.4.1-08, are hereby deleted. The remaining lines for this component, material and environment combination appear as follows:

Component Type	Intended Function	Material	Environment	Aging Effect requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Line Item	Table1 Item	Notes
Heat Exchanger Components	Pressure Boundary	Carbon Steel	Raw Water (Int)	Loss of Material - Crevice Corrosion	Open-Cycle Cooling Water System Program	VIII.E-6	3.4.1-31	A
				Loss of Material - Fouling	Open-Cycle Cooling Water System Program	VIII.E-6	3.4.1-31	A
				Loss of Material - Galvanic Corrosion	Open-Cycle Cooling Water System Program	VIII.E-6	3.4.1-31	A
				Loss of Material - General Corrosion	Open-Cycle Cooling Water System Program	VIII.E-6	3.4.1-31	A
				Loss of Material - MIC	Open-Cycle Cooling Water System Program	VIII.E-6	3.4.1-31	A
				Loss of Material - Pitting Corrosion	Open-Cycle Cooling Water System Program	VIII.E-6	3.4.1-31	A

In Table 3.4.2-8 on page 3.4-131, for Heat Exchanger Tubes exposed to Raw Water (Int), the four lines aligned to Table 1 Item 3.4.1-32 are hereby deleted and replaced with the following:

Component Type	Intended Function	Material	Environment	Aging Effect requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Line Item	Table1 Item	Notes
Heat Exchanger Tubes	Pressure Boundary	Copper-Nickel	Raw Water (Int)	Loss of Material - Crevice Corrosion	Open-Cycle Cooling Water System Program	VII.C1-3	3.3.1-82	A
				Loss of Material - Fouling	Open-Cycle Cooling Water System Program	VII.C1-3	3.3.1-82	A
				Loss of Material - MIC	Open-Cycle Cooling Water System Program	VII.C1-3	3.3.1-82	A
				Loss of Material - Pitting Corrosion	Open-Cycle Cooling Water System Program	VII.C1-3	3.3.1-82	A

RAI 3.3.2.2.4.1-01

LRA Section: Section 3.3.2.2.4.1, page 3.3-34; Table 3.3.1, item number 3.3.1-7, page 3.3-45.

Background: SRP-LR Section 3.3.2.2.4.1 recommends the Water Chemistry program and a plant-specific verification activity to manage the aging effect of cracking due to SSC and cyclic loading in PWR non-regenerative heat exchanger components exposed to treated borated water. The SRP-LR states that an acceptable verification program is to include temperature and radioactivity monitoring of the shell side water, and eddy current testing of the tubes.

Issue: PINGP proposes to manage the aging effect in this component with the Water Chemistry Program and the One-Time Inspection Program. PINGP cites NUREG-1785, Safety Evaluation Report Related to License Renewal of H.B. Robinson Steam Electric Plant, Unit 2, as providing a precedent for use of the One-Time Inspection Program. However, there is insufficient information in the LRA to determine whether the One-Time Inspection program is adequate to perform verification for this aging effect in these components.

Request:

1) Provide a description of the examination methodology to be used to verify effectiveness of the Water Chemistry Program to mitigate the aging effect of cracking due to SCC and cyclic loading in the components that are included in this AMR result line. Also discuss if the methodology is adequate to detect the aging effect of cracking in these components.
2) Will eddy current testing of the tubes be included in the One-Time Inspection Program? If not, then how will potential cracking in the tubes be detected or confirmed not to have occurred?
3) Are there any installed instruments that provide measurements of temperature and radioactivity on the shell side of the heat exchanger?
4) What has been the operating experience with these components? Have there been any failures due to cracking or any other adverse operating experience?
5) Has eddy current testing of the heat exchanger tubes previously been performed? If so, have results indicated evidence of cracking?
6) Address the One-Time Inspections for both LRA line item 3.3.1-7 (non-regenerative heat exchanger components) and 3.3.1-8 (regenerative heat exchanger components) in your response to this RAI.

NSPM Response to RAI 3.3.2.2.4.1-01

Part 1

The purpose of the PINGP Water Chemistry Program is to periodically monitor water chemistry and control detrimental contaminants (such as chlorides, fluorides, dissolved oxygen, and sulfate) to levels below those known to result in cracking. The One-Time Inspection Program provides assurance, through sampling inspections using nondestructive examination techniques, that aging is not occurring, or that the rate of degradation is so insignificant that additional aging management actions are not warranted.

The One-Time Inspection Program, in general, relies upon established nondestructive examination techniques of the PINGP ASME Section XI Inservice Inspection Program for detection of aging effects. Consistent with the guidance of NUREG-1801, Enhanced Visual (VT-1 or equivalent) and/or Volumetric (RT or UT) are used to detect cracking due to SCC and cyclic loading. Fatigue of the Regenerative, Letdown, and Excess Letdown Heat Exchangers is discussed in LRA Section 4.3.2 Non-Class 1 Fatigue. It was concluded that the number of design transients are acceptable for 60 years, and therefore, management of cracking due to cyclic loading is not required.

Part 2

The One-Time Inspection Program was selected in lieu of eddy current testing of the tubes. The One-Time Inspection Program, in general, relies upon established nondestructive examination techniques of the PINGP ASME Section XI Inservice Inspection Program for detection of aging effects. Consistent with the guidance of NUREG-1801, Enhanced Visual (VT-1 or equivalent) and/or Volumetric (RT or UT) methods are used to detect cracking due to SCC. The One-Time Inspection Program uses a representative sampling approach to verify significant degradation is not occurring. Sampling is based on an assessment of material of fabrication, environment, plausible aging effects, and operating experience.

It is anticipated that the heat exchanger tubes addressed by these lines will not be selected for examination. Instead, inspections would occur on components with the equivalent material/environment combinations. As some materials and component types to be examined are not included in the PINGP ASME Section XI Inservice Inspection Program, the use of alternate examination techniques not specified by ASME Section XI may be more appropriate. In such cases, approaches equivalent to Inservice Inspection requirements will be implemented where applicable. These alternate inspection methods would include documentation of component identification, examination technique, acceptance criteria, flaw evaluation requirements and technical justification of suitability to detect the aging effects of interest. Note that the Regenerative Heat Exchanger Tubes are not within the scope of License Renewal.

Part 3

Liquid Radiation Monitor 1-R-39 (Unit 1) and 2-R-39 (Unit 2), monitor the Component Cooling System for reactor coolant leakage, including leakage from the Chemical and Volume Control System Seal Water, Letdown and Excess Letdown Heat Exchangers. These points are monitored on the plant process computer. Temperature indicators TI 15317 (Unit 1) and TI 15325 (Unit 2); and TI 15318 (Unit 1) and TI 15326 (Unit 2) are located downstream of the Letdown and Seal Water Heat Exchangers, respectively, on the Component Cooling Water side. These points are monitored on the plant process computer. Temperature elements TE-12161 (Unit 1) and TE-12165 (Unit 2) are located downstream of the Excess Letdown Heat Exchangers on the Component Cooling Water side. These points provide local indication only.

Part 4

A review of operating history did not reveal any degradation of the Regenerative, Letdown, and Excess Letdown Heat Exchanger components. Some leakage from gaskets (which are short lived and out of scope of license renewal), located on the channel heads of the heat exchangers, was noted.

Part 5

There is no record of, or requirement for, eddy current testing of the Regenerative, Letdown, and Excess Letdown Heat Exchangers. Eddy current testing of these heat exchangers would result in high doses to workers.

Part 6

The Regenerative, Letdown, and Excess Letdown Heat Exchangers were all discussed above.

RAI 3.5.2.2-1

NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," Revision 1, discusses the use of ASTM Standards C227-50 and C295-54 for investigations and petrographic examinations of concrete aggregates. However, License Renewal Application (LRA) Section 3.5.2.2.2.2, "Aging Management of Inaccessible Areas – Subsection 2," states that Prairie Island Nuclear Generating Plant (PINGP) tests and petrographic examinations were performed in accordance with ASTM Standard C289. While reviewing ASTM Standard C289 for compliance with the suggested standards, the staff noted that C289 states, "when this test method is used to evaluate the potential reactivity it must be used in combination with other methods."

The staff requests that the applicant provide a discussion and basis for the determination that ASTM C289 by itself adequately verifies the aggregates are not reactive and satisfies the requirements of ASTM C227-50 and C295-54 as suggested by the GALL report.

NSPM Response to RAI 3.5.2.2-1

PINGP USAR Section 12.2.3.2 entitled, "Codes" provides a list of standards and specifications in use at PINGP for concrete materials. ASTM Specification C295, "Petrographic Examination" is included on the list as one method used to evaluate aggregates for reactivity. The report for concrete testing performed in June of 1968 by the Twin Cities Testing and Engineering Laboratory Inc. of St Paul, Minnesota include reactivity results for aggregates based on testing in accordance with ASTM Standard C295 and ASTM Standard C289, "Test for Potential Reactivity of Aggregates." These test results determined that the aggregates were not potentially reactive.

LRA Section 3.5.2.2.2.2, Aging Management of Inaccessible Areas, Subsection 2, should have included ASTM Standard C295 as another one of the test methods used at PINGP to evaluate aggregates for reactivity. Because the ASTM C295 Standard was also used for PINGP, the GALL Report criterion is satisfied.

RAI 3.5.2.2-2

GALL Report line item II.A3-2 states additional inspections may be necessary to detect aging effects in dissimilar metal welds and bellows assemblies due to stress corrosion cracking (SCC), particularly if the material is not shielded from a corrosive environment. However, LRA Section 3.5.2.2.1.7, "Cracking due to Stress Corrosion Cracking (SCC)," states that additional inspections are not necessary for the stainless steel penetration sleeves and bellows with dissimilar metal welds since the components are located in a non-corrosive environment where the temperature does not reach the threshold for SCC.

The staff requests that the applicant provide (1) the highest temperature that the stainless steel penetration sleeves, penetration bellows, and dissimilar metal welds have experienced, and (2) demonstrate that chemical elements that support SCC have been monitored or measured to ensure a non-aggressive chemical environment.

NSPM Response to RAI 3.5.2.2-2

Temperatures for stainless steel penetration sleeves, penetration bellows, and dissimilar metal welds are not routinely monitored since their design is based on the maximum design temperatures expected during an accident and not the normal operating temperature. The sentence referenced by this RAI requires clarification.

Therefore, in LRA Section 3.5.2.2.1.7, the fifth sentence of the second paragraph is hereby revised to read as follows:

> "Additionally, welds are located in an air indoor environment."

SCC is an aging mechanism that requires the simultaneous action of a corrosive environment, temperatures in excess of 140 degrees F, and a susceptible material. Elimination of any one of these elements eliminates susceptibility to SCC in accordance with EPRI guidance documents. The pressure retaining welds, dissimilar metal welds, penetration sleeves, and bellow assemblies are not exposed to a corrosive environment (see discussion on plant environment below).

The penetration sleeves, penetration bellow assemblies, and dissimilar metal welds are located inside the shield buildings in a sheltered indoor air environment, and are not located in an outdoor air or buried environment. The PINGP indoor air environment is not aggressive based on the following rationale. The plant is located in a rural area along the upper Mississippi River, and draws its cooling water from the river, a fresh water source. It is not located in a marine area and therefore not exposed to a salt air/water environment. Additionally, the U. S. Environmental Protection Agency (EPA) has established National Ambient Air Quality Standards (NAAQS) for six common pollutants (i.e., nitrogen dioxide, sulfur dioxide, carbon monoxide, lead, ozone, and particulate matter), and has designated all areas of the United States as having air quality better ("attainment") or worse ("non-attainment") than the NAAQS. The air quality in the area of PINGP is better than the NAAQS for all criteria pollutants (Reference PINGP LRA Environmental Report, Section 2.4). Therefore, SCC is not an aging effect requiring management since the conditions necessary for SCC do not exist.

Pressure retaining welds, dissimilar metal welds, penetration sleeves, and bellow assemblies are managed for aging effects such as cracking and loss of material by the ASME Section XI, Subsection IWE Program (Code Category E-A) and the 10 CFR Part 50 Appendix J Program (Code Category E-P) which include examination criteria adequate to detect aging effects. Any observed condition with the potential to impact an intended function is evaluated in accordance with the corrective action process.

The existing IWE inspection program elected not to implement the weld examination requirement for Code Categories E-B and E-F as allowed by 10 CFR 50.55a (b)(2)(ix)(C). Per the PINGP IWE inspection program, any accessible welds in these categories are an integral part of the liner, and as such are part of the area inspected during the performance of Category E-A examinations. Examination Category E-A requirements are considered sufficient to identify any degraded condition for containment penetration welds, dissimilar metal welds, penetration sleeves, and bellow assemblies, and therefore additional inspections are not necessary.

A review of plant operating experience identified no cracking of the penetration bellow assemblies, and reactor containment vessel leakage has not been identified as a concern.

RAI 3.6-1

Increased resistance of connections due to oxidation can occur in transmission conductors and connections, and in switchyard bus and connections. NUREG-1801, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants” (SRP-LR), Section 3.6.2.2.3, recommends a plant-specific AMP for the management of increase resistance of connections due to oxidation or loss of pre-load in transmission conductors and connections and in switchyard bus and connections.

LRA Section 3.6.2.2.3 states that there are no aging effects from the outdoor environment that would cause the loss of the capacity to provide electrical connections to specified sections of an electrical circuit to deliver voltage, current, or signals.

The staff requests that the applicant provide a basis for the applicant’s determination that increased resistance of connections due to oxidation or loss of pre-load in transmission conductors and connections, and in switchyard bus and connections is not an aging effect requiring management.

NSPM Response to RAI 3.6-1

For Transmission Cables and Conductors, high-voltage transmission conductors and connections were reviewed for aging from vibration, loss of material, wind induced abrasion, fatigue, loss of conductor strength, corrosion, increased resistance of connections, oxidation, and loss of pre-load. The PINGP Operating Experience (OE) review did not identify any aging problems with the high voltage transmission conductors and connections that resulted from vibration, wind induced abrasion, fatigue, increased resistance of connections, or loss of pre-load.

The most prevalent mechanism contributing to loss of conductor strength of an ACSR (aluminum conductor steel reinforced) transmission conductor is corrosion, which includes corrosion of the steel core and aluminum strand pitting. For ACSR conductors, degradation begins as a loss of zinc from the galvanized steel core wires. As discussed in LRA Section 3.6.2.2.3, the corrosion rates for the cable used at PINGP are within the allowable strength limit margins of the Ontario Hydroelectric test reference. The LRA section states:

> "Corrosion in ACSR conductors is a slow acting mechanism. Corrosion rates are dependent on air quality. PINGP is located in an agricultural area with no nearby industries that could contribute to corrosive air quality. Corrosion testing of transmission conductors at Ontario Hydroelectric showed a 30 percent loss of composite conductor strength of an 80-year-old ACSR conductor. The Institute of Electrical and Electronic Engineers National Electrical Safety Code (NESC) requires that tension on installed conductors be a maximum of 60% of the ultimate conductor strength. Therefore, assuming a 30% loss of strength, there would be remaining margin between what is required by the NESC and the actual conductor strength. In determining actual conductor tension, the NESC considers various loads imposed by ice, wind, and temperature as well as length of conductor span.
>
> PINGP transmission conductors in scope for License Renewal are short spans located within the PINGP site, and are designed for heavy loading; therefore, the Ontario Hydroelectric heavy loading zone study is aligned with respect to loads imposed by weather conditions.
>
> The 636 MCM ACSR transmission conductor used in the PINGP Switchyard will be used as an illustration. The ultimate strength of a 636 MCM (24/7 strands) ACSR conductor is 22,600 lbs and the maximum design tension for this conductor is 3,500 lbs. The margin between the maximum design tension and the ultimate strength is 19,100 lbs. Therefore, there is an 84.5% ultimate strength margin (19,100/22,600). The Ontario Hydroelectric study showed a 30% loss of composite conductor strength in an 80-year old conductor. Since the margin for the PINGP conductors is greater than the margin loss due to aging, remaining safety margin exists on the aged conductors.
>
> The Ontario Hydroelectric test results demonstrate that the expected material loss that would be incurred on the PINGP ACSR transmission conductors is acceptable for the period of extended operation. Therefore, no aging management is required for loss of material and loss of strength on the ACSR transmission conductors at PINGP."

For Switchyard Bus and Connections, switchyard bus connections within the component boundaries are bolted, welded and crimped aluminum connections for cables. The PINGP OE review has not identified aging problems with the high voltage switchyard bus and connections that resulted from loss of material, wind induced abrasion and fatigue loss of conductor strength, corrosion increased resistance of connections, oxidation or loss of pre-load. Bellville washers are also used at PINGP to minimize the effects of loose connections from loss of pre-load. Failures of Bellville washers (causing loose connections) were noted from industry operating experience, whereby hydrogen entrapment with plated steel washers caused embrittlement and stress cracking of the plated washer leading to loose connections. Action has been taken by the industry to correct this issue. The Prairie Island design includes the use of stainless steel Bellville washers. The issue of hydrogen entrapment causing failures is not an issue for stainless steel Bellville washers used at PINGP.

A degree of surface oxidation does initially occur on aluminum switchyard bus and connection portions exposed to Air - Outdoor environments, but the oxidation levels do not adversely impact the bus and connections from appreciable losses of material. The initial oxidation of exposed aluminum actually provides a protective layer, whereby further oxidation is progressively slowed to negligible levels. The internal contact surfaces of the switchyard bolted connections are not exposed to a moisture environment that would contribute to corrosion of the connection contact surface area. A loose connection (from any other cause, such as inadequate tightening during maintenance) is required to provide an environment for the onset of corrosion of the internal connection surfaces to occur.

For the ambient environmental conditions at the Prairie Island substation, no aging effects have been identified for switchyard bus and connections that could cause a loss of intended function for the extended period of operation. Therefore, there are no applicable or significant aging effects for the aluminum bus and aluminum alloy connections that require aging management. As a result, no plant specific license renewal aging management program is required for Transmission Cables and Conductors, and Switchyard Bus and Connections.

RAI 3.6-2

Tie wraps may be taken credit for in seismic analysis and in plant design specifications primarily for separation of cables to preclude ampacity degrading. Operating experience has identified occurrences where tie wraps have become brittle, degraded, or are missing and whose failures have affected the safety functions of other system/components.

The PINGP LRA does not address tie wraps as a commodity type which has been reviewed to determine if tie wraps are within the scope of license renewal and subject to an aging management review (AMR).

The staff requests that the applicant explain the basis for determining that tie wraps are not within the scope of license renewal and not subject to an AMR. In particular, address if tie wraps are taken credit for in seismic analysis or/and design specifications in the current licensing basis. Address whether tie wraps are used in applications where they are non-safety related components, whose failure could affect safety-related intended functions. If tie wraps are taken credit for in a seismic analysis, provide a quantitative analysis of the effects of cables spacing not being maintained as original design specifications (due to tie wraps failure). The analysis should provide the worst case scenario with ampacity reduction and the maximum amperes required for motors to start and run during a design basis accident.

NSPM Response to RAI 3.6-2

The use of tie wraps at PINGP has been reviewed, and it is confirmed that tie wraps are not within the scope of license renewal and not subject to an AMR.

Debris Considerations

Industry and PINGP OE were reviewed. Foreign material debris, such as broken tie wraps, can cause equipment functional failures. PINGP equipment that is sensitive to debris, such as broken tie wraps, are designed to be protected by enclosures. Maintenance-induced failures from inadequate foreign material exclusion (FME) practices involving tie wraps do not bring tie wraps in scope and do not require AMR for License Renewal purposes. An analysis of the containment sump for the safety-related recirculation mode of post-accident operation, considered the effects of debris, including tie wraps. No occurrences were identified involving a non-safety related tie wrap failure affecting safety-related intended functions at PINGP.

Seismic Support Considerations

Tie wraps are used to assist in the orderly installation of cables in tray at PINGP. Tie wraps are not credited for support in the PINGP seismic analyses

Ampacity Considerations

PINGP USAR Section 8.7 states "They [power cables] are installed with only a single layer of cables per tray and clamped in the ladder to ensure that a specified spacing exists between these cables to ensure that air cooling is available."

The LR project conducted a cable insulation aging assessment for the hypothetical configuration of unspaced single layer power cables in trays with continuous heavy current loading for motors credited to start and run during a design basis accident. For the continuous heavy current loaded power cables the free-air rating was based on IPCEA P-46-426, ICPA P-54-440, and the NEC. For each of the continuous heavy current loaded power cables, the full load amps or actual amps value was obtained. An aging assessment screening derate factor of 50% was applied to the power cables' free air allowable ampacity value. No continuous heavily loaded power cables in scope of License Renewal were identified to be operating at or above 50% of free air allowable ampacity. The aging assessment concluded that power cables have adequate design margin to accommodate a hypothetical not spaced configuration, 60 years of operational aging, and to start and run credited motors during a design basis accident.

The following example illustrates the process used for aging assessments. A power cable to a Charging Pump Motor, 125 HP (460V), operates at 145 amps full load. The 3/C 4/0 copper allowable ampacity for free air is 359 amps. The 145 full load amps drawn by the motor is 40% of the free air allowable ampacity of the cable. (The free air allowable ampacity values, as well as derating criteria, reside in IPCEA P-46-426, ICPA P-54-440, and the NEC.)

Enclosure 2

Updated Preliminary License Renewal Commitment List

13 Pages

Preliminary License Renewal Commitments

The following table provides the list of preliminary commitments included in the Application for Renewed Operating Licenses (LRA) for Prairie Island Nuclear Generating Plant (PINGP) Units 1 and 2. These commitments reflect the contents of the LRA as submitted, and any updates provided in subsequent correspondence, but are considered preliminary in that the specific wording of some commitments may change, and additional commitments may be made, during the NRC review of the LRA.

The final commitments as submitted by NSPM, and accepted by NRC, are expected to be confirmed in the NRC's Safety Evaluation Report (SER) for the renewed operating licenses. The final commitments, as confirmed in the SER, will become effective upon NRC issuance of the renewed operating licenses. In addition, as stated in the LRA, the final commitments will be incorporated into the Updated Safety Analysis Report (USAR).

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
1	Each year, following the submittal of the PINGP License Renewal Application and at least three months before the scheduled completion of the NRC review, NMC will submit amendments to the PINGP application pursuant to 10 CFR 54.21(b). These revisions will identify any changes to the Current Licensing Basis that materially affect the contents of the License Renewal Application, including the USAR supplements.	12 months after LRA submittal date and at least 3 months before completion of NRC review	1.4
2	Following the issuance of the renewed operating license, the summary descriptions of aging management programs and TLAAs provided in Appendix A, and the final list of License Renewal commitments, will be incorporated into the PINGP USAR as part of a periodic USAR update in accordance with 10 CFR 50.71(e). Other changes to specific sections of the PINGP USAR necessary to reflect a renewed operating license will also be addressed at that time.	First USAR update in accordance with 10 CFR 50.71(e) following issuance of renewed operating licenses	A1.0
3	An Aboveground Steel Tanks Program will be implemented. Program features will be as described in LRA Section B2.1.2.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.2
4	Procedures for the conduct of inspections in the External Surfaces Monitoring Program, Structures Monitoring Program, Buried Piping and Tanks Inspection Program, and the RG 1.127	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.6

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
	Inspection of Water-Control Structures Associated with Nuclear Power Plants Program will be enhanced to include guidance for visual inspections of installed bolting.		
5	A Buried Piping and Tanks Inspection Program will be implemented. Program features will be as described in LRA Section B2.1.8.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.8
6	The Closed-Cycle Cooling Water System Program will be enhanced to include periodic inspection of accessible surfaces of components serviced by closed-cycle cooling water when the systems or components are opened during scheduled maintenance or surveillance activities. Inspections are performed to identify the presence of aging effects and to confirm the effectiveness of the chemistry controls. Visual inspection of component internals will be used to detect loss of material and heat transfer degradation. Enhanced visual or volumetric examination techniques will be used to detect cracking. [Revised in letter dated 1/20/2009 in response to RAI 3.3.2-13-01]	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.9
7	The Compressed Air Monitoring Program will be enhanced to require that Station and Instrument Air System air quality be monitored and maintained in accordance with the instrument air quality guidance provided in ISA S7.0.01-1996. Particulate testing will be revised to use a particle size methodology as specified in ISA S7.0.01.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.10
8	An Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program will be completed. Program features will be as described in LRA Section B2.1.11.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.11

Preliminary License Renewal Commitments

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
9	An Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program will be implemented. Program features will be as described in LRA Section B2.1.12.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.12
10	An Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program will be implemented. Program features will be as described in LRA Section B2.1.13.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.13
11	The External Surfaces Monitoring Program will be enhanced as follows: • The scope of the program will be expanded as necessary to include all metallic and non-metallic components within the scope of license renewal that require aging management in accordance with this program. • The program will ensure that surfaces that are inaccessible or not readily visible during plant operations will be inspected during refueling outages. • The program will ensure that surfaces that are inaccessible or not readily visible during both plant operations and refueling outages will be inspected at intervals that provide reasonable assurance that aging effects are managed such that the applicable components will perform their intended function during the period of extended operation.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.14
12	The Fire Protection Program will be enhanced to require periodic visual inspection of the fire barrier walls, ceilings, and floors to be performed during walkdowns at least once every refueling cycle. [Revised in letter dated 12/5/2008 in response to RAI B2.1.15-3]	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.15

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
13	The Fire Water System Program will be enhanced as follows: • The program will be expanded to include eight additional yard fire hydrants in the scope of the annual visual inspection and flushing activities. • The program will require that sprinkler heads that have been in place for 50 years will be replaced or a representative sample of sprinkler heads will be tested using the guidance of NFPA 25, "Inspection, Testing and Maintenance of Water-Based Fire Protection Systems" (2002 Edition, Section 5.3.1.1.1). Sample testing, if performed, will continue at a 10-year interval following the initial testing.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.16
14	The Flux Thimble Tube Inspection Program will be enhanced as follows: • The program will require that the interval between inspections be established such that no flux thimble tube is predicted to incur wear that exceeds the established acceptance criteria before the next inspection. • The program will require that re-baselining of the examination frequency be justified using plant-specific wear rate data unless prior plant-specific NRC acceptance for the re-baselining was received. If design changes are made to use more wear-resistant thimble tube materials, sufficient inspections will be conducted at an adequate inspection frequency for the new materials. • The program will require that flux thimble tubes that cannot be inspected must be removed from service.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.18

Preliminary License Renewal Commitments

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
15	The Fuel Oil Chemistry Program will be enhanced as follows: • Particulate contamination testing of fuel oil in the eleven fuel oil storage tanks in scope of License Renewal will be performed, in accordance with ASTM D 6217, on an annual basis. • One-time ultrasonic thickness measurements will be performed at selected tank bottom and piping locations prior to the period of extended operation.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.19
16	A Fuse Holders Program will be implemented. Program features will be as described in LRA Section B2.1.20.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.20
17	An Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program will be implemented. Program features will be as described in LRA Section B2.1.21	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.21
18	An Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program will be implemented. Program features will be as described in LRA section B2.1.22.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.22
19	The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program will be enhanced as follows: • Program implementing procedures will be revised to ensure the components and structures subject to inspection are clearly identified. Program inspection procedures will be enhanced to include the parameters corrosion and wear where omitted.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.23

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
20	A Metal-Enclosed Bus Program will be implemented. Program features will be as described in LRA Section B2.1.26.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.26
21	For the Nickel-Alloy Nozzles and Penetrations Program, PINGP commits to the following activities for managing the aging of nickel-alloy components susceptible to primary water stress corrosion cracking: • Comply with applicable NRC orders, and • Implement applicable NRC Bulletins, Generic Letters, and staff-accepted industry guidelines.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.27
22	The Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program will be enhanced as follows: • The program will require that any deviations from implementing the appropriate required inspection methods of the NRC First Revised Order EA-03-009, “Issue of Order Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors,” dated February 20, 2004 (Order), as amended, will be submitted for NRC review and approval in accordance with the Order, as amended. • The program will require that any deviations from implementing the required inspection frequencies mandated by the Order, as amended, will be submitted for NRC review and approval in accordance with the Order, as amended. • The program will require that relevant flaw indications detected during the augmented inspections of the upper vessel head penetration nozzles will be evaluated in	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.28

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
	accordance with the criteria provided in the letter from Mr. Richard Barrett, NRC, Office of Nuclear Reactor Regulation (NRR), Division of Engineering to Alex Marion, Nuclear Energy Institute (NEI), dated April 11, 2003, or in accordance with NRC-approved Code Cases that incorporate the flaw evaluation procedures and criteria of the NRC's April 11, 2003, letter to NEI. • The program will require that, if leakage or evidence of cracking in the vessel head penetration nozzles (including associated J-groove welds) is detected while ranked in the "Low," "Moderate," or "Replaced" susceptibility category, the nozzles are to be immediately reclassified to the "High" susceptibility category and the required augmented inspections for the "High" susceptibility category are to be implemented during the same outage the leakage or cracking is detected.		
23	A One-Time Inspection Program will be completed. Program features will be as described in LRA Section B2.1.29.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.29
24	A One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program will be completed. Program features will be as described in LRA Section B2.1.30.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.30
25	For the PWR Vessel Internals Program, PINGP commits to the following activities for managing the aging of reactor vessel internals components: • Participate in the industry programs for investigating and managing aging effects on reactor internals; • Evaluate and implement the results of the industry programs as applicable to the reactor internals; and	U1 - 8/9/2011 U2 - 10/29/2012	B2.1.32

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
	• Upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.		
26	The Reactor Head Closure Studs Program will be enhanced to incorporate controls that ensure that any future procurement of reactor head closure studs will be in accordance with the material and inspection guidance provided in NRC Regulatory Guide 1.65.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.33
27	The Reactor Vessel Surveillance Program will be enhanced as follows: • A requirement will be added to ensure that all withdrawn and tested surveillance capsules, not discarded as of August 31, 2000, are placed in storage for possible future reconstitution and use. • A requirement will be added to ensure that in the event spare capsules are withdrawn, the untested capsules are placed in storage and maintained for future insertion.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.34
28	The RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program will be enhanced as follows: • The program will include inspections of concrete and steel components that are below the water line at the Screenhouse and Intake Canal. The scope will also require inspections of the Approach Canal, Intake Canal, Emergency Cooling Water Intake, and	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.35

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
	Screenhouse immediately following extreme environmental conditions or natural phenomena including an earthquake, flood, tornado, severe thunderstorm, or high winds. • The program parameters to be inspected will include an inspection of water-control concrete components that are below the water line for cavitation and erosion degradation. • The program will visually inspect for damage such as cracking, settlement, movement, broken bolted and welded connections, buckling, and other degraded conditions following extreme environmental conditions or natural phenomena.		
29	A Selective Leaching of Materials Program will be completed. Program features will be as described in LRA B2.1.36.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.36
30	The Structures Monitoring Program will be enhanced as follows: • The following structures, components, and component supports will be added to the scope of the inspections: ○ Approach Canal ○ Fuel Oil Transfer House ○ Old Administration Building and Administration Building Addition ○ Component supports for cable tray, conduit, cable, tubing tray, tubing, non-ASME vessels, exchangers, pumps, valves, piping, mirror insulation, non-ASME valves, cabinets, panels, racks, equipment enclosures, junction boxes, bus	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.38

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
	ducts, breakers, transformers, instruments, diesel equipment, housings for HVAC fans, louvers, and dampers, HVAC ducts, vibration isolation elements for diesel equipment, and miscellaneous electrical and mechanical equipment items o Miscellaneous electrical equipment and instrumentation enclosures including cable tray, conduit, wireway, tube tray, cabinets, panels, racks, equipment enclosures, junction boxes, breaker housings, transformer housings, lighting fixtures, and metal bus enclosure assemblies o Miscellaneous mechanical equipment enclosures including housings for HVAC fans, louvers, and dampers o SBO Yard Structures and components including SBO cable vault and bus duct enclosures. o Fire Protection System hydrant houses o Caulking, sealant and elastomer materials o Non-safety related masonry walls that support equipment relied upon to perform a function that demonstrates compliance with a regulated event(s). • The program will be enhanced to include additional inspection parameters. • The program will require an inspection frequency of once every five (5) years for structures and structural components within the scope of the program. The frequency of inspections can be adjusted, if necessary, to allow for early detection and timely correction of negative trends.		

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
	• The program will require periodic sampling of groundwater and river water chemistries to ensure they remain non-aggressive.		
31	A Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program will be implemented. Program features will be as described in LRA Section B2.1.39.	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.39
32	The Water Chemistry Program will be enhanced as follows: • The program will require increased sampling to be performed as needed to confirm the effectiveness of corrective actions taken to address an abnormal chemistry condition. • The program will require Reactor Coolant System dissolved oxygen Action Level limits to be consistent with the limits established in the EPRI PWR Primary Water Chemistry Guidelines." [Revised in letter dated 12/5/2008 in response to RAI B2.1.40-3]	U1 - 8/9/2013 U2 - 10/29/2014	B2.1.40
33	The Metal Fatigue of Reactor Coolant Pressure Boundary Program will be enhanced as follows: • The program will monitor the six component locations identified in NUREG/CR-6260 for older vintage Westinghouse plants, either by tracking the cumulative number of imposed stress cycles using cycle counting, or by tracking the cumulative fatigue usage, including the effects of coolant environment. The following locations will be monitored: ○ Reactor Vessel Inlet and Outlet Nozzles ○ Reactor Pressure Vessel Shell to Lower Head	U1 - 8/9/2013 U2 - 10/29/2014	B3.2

Preliminary License Renewal Commitments

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
	◦ RCS Hot Leg Surge Line Nozzle ◦ RCS Cold Leg Charging Nozzle ◦ RCS Cold Leg Safety Injection Accumulator Nozzle ◦ RHR-to-Accumulator Piping Tee • Program acceptance criteria will be clarified to require corrective action to be taken before a cumulative fatigue usage factor exceeds 1.0 or a design basis transient cycle limit is exceeded. [Revised in letter dated 1/9/2009 in response to RAI 4.3.1.1-1]		
34	Reactor internals baffle bolt fatigue transient limits of 1835 cycles of plant loading at 5% per minute and 1835 cycles of plant unloading at 5% per minute will be incorporated into the Metal Fatigue of Reactor Coolant Pressure Boundary Program and USAR Table 4.1-8.	U1 - 8/9/2013 U2 - 10/29/2014	B3.2
35	NSPM will perform an ASME Section III fatigue evaluation of the lower head of the pressurizer to account for effects of insurge/outsurge transients. The evaluation will determine the cumulative fatigue usage of limiting pressurizer component(s) through the period of extended operation. The analyses will account for periods of both "Water Solid" and "Standard Steam Bubble" operating strategies. Analysis results will be incorporated, as applicable, into the Metal Fatigue of Reactor Coolant Pressure Boundary Program. [Revised in letter dated 1/9/2009 in response to RAI 4.3.1.1-1]	U1 - 8/9/2013 U2 - 10/29/2014	4.3.1.3
36	NSPM will complete fatigue calculations for the pressurizer surge line hot leg nozzle and the charging nozzle using the methodology of the ASME Code (Subsection NB) and will	April 30, 2009	4.3.3

Commitment Number	Commitment	Implementation Schedule	Related LRA Section Number
	report the revised CUFs and CUFs adjusted for environmental effects at these locations as an amendment to the PINGP LRA. Conforming changes to LRA Section 4.3.3, "PINGP EAF Results," will also be included in that amendment to reflect analysis results and remove references to stress-based fatigue monitoring. [Added in letter dated 1/9/2009 in response to RAI 4.3.1.1-1]		