PrairieIslandNPEm Resource

From: Vincent, Robert [Robert.Vincent@xenuclear.com]
Sent: Thursday, February 26, 2009 12:37 PM
To: Richard Plasse; Nathan Goodman; Stuart Sheldon
Cc: Eckholt, Gene F.; Davis, Marlys E.
Subject: PINGP Letter Dated 2/26/09 Responding to RAIs and Follow up questions
Attachments: 20090226 Response to RAI Letter dtd 2-20-09.pdf; 20090226 Response to RAI Letter dtd 2-20-09.doc

Attached are pdf and WORD versions of the letter responding to NRC RAIs issued 2/20/09 and various followup questions discussed in conference calls on 2/3, 2/10 and 2/11.

Please call if you have any problems with the files.

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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 February 20, 2009 and Follow Up Questions 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 February 20, 2009, the NRC transmitted Requests for Additional Information (RAIs) regarding that application. Enclosure 1 of this letter provides the text of each RAI followed by the NSPM response.

NSPM letters dated December 18, 2008, and January 9, January 20 and February 6, 2009, among others, provided responses to Requests for Additional Information (RAIs) concerning the application. In conference calls on February 3, 2009, February 10, 2009 and February 11, 2009, the NRC raised follow up questions about the LRA and certain of those RAI responses. Enclosure 2 of this letter provides a summary of each follow up question followed by the NSPM response.

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 or revisions to existing commitments.

I declare under penalty of perjury that the foregoing is true and correct.
Executed on February 26, 2009.

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 February 20, 2009

RAI AMR-3.3.2.9-2

In License Renewal Application (LRA) Table 3.3.2-9, pages 3.3-198, 199 and 200, fire protection system, for copper alloy heat exchanger components and heat exchanger tubes in an internal environment of raw water, PINGP has credited the Fire Water System Program to manage the aging effects loss of material and heat transfer degradation. These lines reference footnote E, and NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," Revision 1, item VII.C1-3. The GALL Report item recommends AMP XI.M20, Open-Cycle Cooling Water Program to manage these aging effects for heat exchangers. The GALL AMP recommends chemical treatment whenever the potential for biofouling species exists as part of the preventive actions and a test program to verify heat transfer capabilities.

Please justify why Open-Cycle Cooling Water System Program is not used.

NSPM Response to RAI AMR-3.3.2.9-2

The Fire Water System Program is used in lieu of the Open-Cycle Cooling Water System Program to manage aging of Fire Protection (FP) System components that are exposed to a raw water environment other than open-cycle cooling water. For LRA Table 3.3.2-9, Auxiliary Systems - Fire Protection System – Summary of Aging Management Evaluation, on Pages 3.3-198, 199 and 200, for copper alloy heat exchanger components and heat exchanger tubes in an internal environment of raw water, the components are exposed to untreated Mississippi River (ultimate heat sink) water. Although the Mississippi River (ultimate heat sink) is the source for both the Cooling Water (CL) System and the FP System, these FP System components are supplied by the Fire Water sub-system which is not managed by the Open-Cycle Cooling Water System Program. Therefore, PINGP has appropriately credited the Fire Water System Program.

In addition, the affected components, 121 Motor Driven Fire Pump Enclosure Cooler and the 122 Diesel Driven Fire Pump Heat Exchanger, are not safety related components and are not within the scope of NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment." Preventive actions associated with the PINGP Fire Water System Program include periodic flushing, performance testing, and inspections. Heat transfer degradation of the 121 Motor Driven Fire Pump Enclosure Cooler is managed by periodic inservice flushing during the 121 Motor Driven Fire Pump Performance Test. Heat transfer degradation of the 122 Diesel Driven Fire Pump Heat Exchanger is managed by periodically monitoring and recording the engine operating temperature during the 122 Diesel Driven Fire Pump Performance Test.

RAI 4.3.1-1

The Prairie Island Nuclear Generating Plant (PINGP) metal fatigue of reactor coolant pressure boundary management program relies on transient cycle monitoring to evaluate the fatigue usage described in the license renewal application. This approach tracks the number of occurrences of significant thermal and pressure transients (significant events) and compares the cumulative cycles, projected to cover the renewal period, against the number of design cycles specified in the design specifications. The projected cycles are then used to evaluate the total cumulative usage factor (CUF) which covers the period of extended operation. For this approach to work, none of the significant events tracked should produce stresses greater than those that would be produced by the design transients. That is, the P-T (Pressure and Temperature) characteristics, including their values, ranges, and rates, all must be bounded within those defined in the design specifications.

(a) Please describe the procedures that PINGP has been using for tracking thermal activities so the staff can confirm that the PINGP aging management program will ensure that P-T characteristics, including their values, ranges, and rates remain bounded within the range defined in the design specifications during the renewed license term.

(b) Please provide a histogram (cycle accumulating charts) of heatup transient history, and a histogram for the cooldown transient as well.

NSPM Response to RAI 4.3.1-1

Part (a):

The significant thermal and pressure transients used to calculate cumulative usage factors are defined in the design specifications for each Class 1 component. These design transients are described in Section 4.1.4 and Table 4.1-8 of the PINGP USAR, and are also provided in Table 4.3-1 of the PINGP LRA. The number of occurrences of design cycles is tracked by the Metal Fatigue of Reactor Coolant Pressure Boundary Program as described in Section B3.2 of the PINGP LRA.

PINGP Technical Specifications Section 5.5.5 establishes the requirement to track the USAR Section 4.1.4 cyclic and transient occurrences to ensure that components are maintained within the design limits. This requirement is implemented by a PINGP surveillance procedure. The procedure requires that records be kept of the applicable thermal and pressure transients. These records are maintained as on-going transient summary sheets contained in the procedure itself.

The PINGP surveillance procedure lists the design pressure and temperature transients from USAR Section 4.1.4, and contains a summary sheet for each design transient which lists every cycle counted for that transient. At least once each quarter, the program owner conducts a review of plant operating records to determine if an "operating cycle" has occurred for any of the design pressure or temperature transients. If a cycle has occurred, the program owner will add the event to the proper cycle summary sheet along with a brief description of the transient cycle. The majority of transient cycles logged to date have been associated with heatups, cooldowns and reactor trip events.

For heatups and cooldowns, the maximum hourly rate (^{o}F/hr) is recorded on the cycle summary sheet for each heatup and cooldown. A review of past plant heatup and cooldown data indicates that the average plant heatup rate has been approximately 40 ^{o}F/hr and the average plant cooldown rate has been about 70 ^{o}F/hr. For design purposes, the transient parameters response for the heatup and cooldown transients is based on a rate of 100 ^{o}F/hr. Therefore, the design transient responses remain bounding with respect to the actual plant heatup and cooldown rates.

For reactor trip events, the initial reactor power level is recorded on the cycle summary sheet. Approximately 65% of the reported reactor trip events in both units have occurred from an initial power level between 75% and 100% power. The remaining 35% of reactor trip events occurred from an initial power level lower than 75% of full power. For design purposes, the reactor trip transient is based on a trip from 100% power conditions. Therefore, the design transient responses remain bounding with respect to the actual plant reactor trip events.

If a design limit for the number or severity of a transient were exceeded (e.g., RCS exceeds 100 ^{o}F/hr during heatup or cooldown), a CAP would be initiated, and the procedure requires that an analysis be performed to determine the effect on system components. The Corrective Action Program would determine appropriate actions, potentially including reanalysis, repair, or replacement of the affected components, and assessment of additional pressure boundary locations that may be affected.

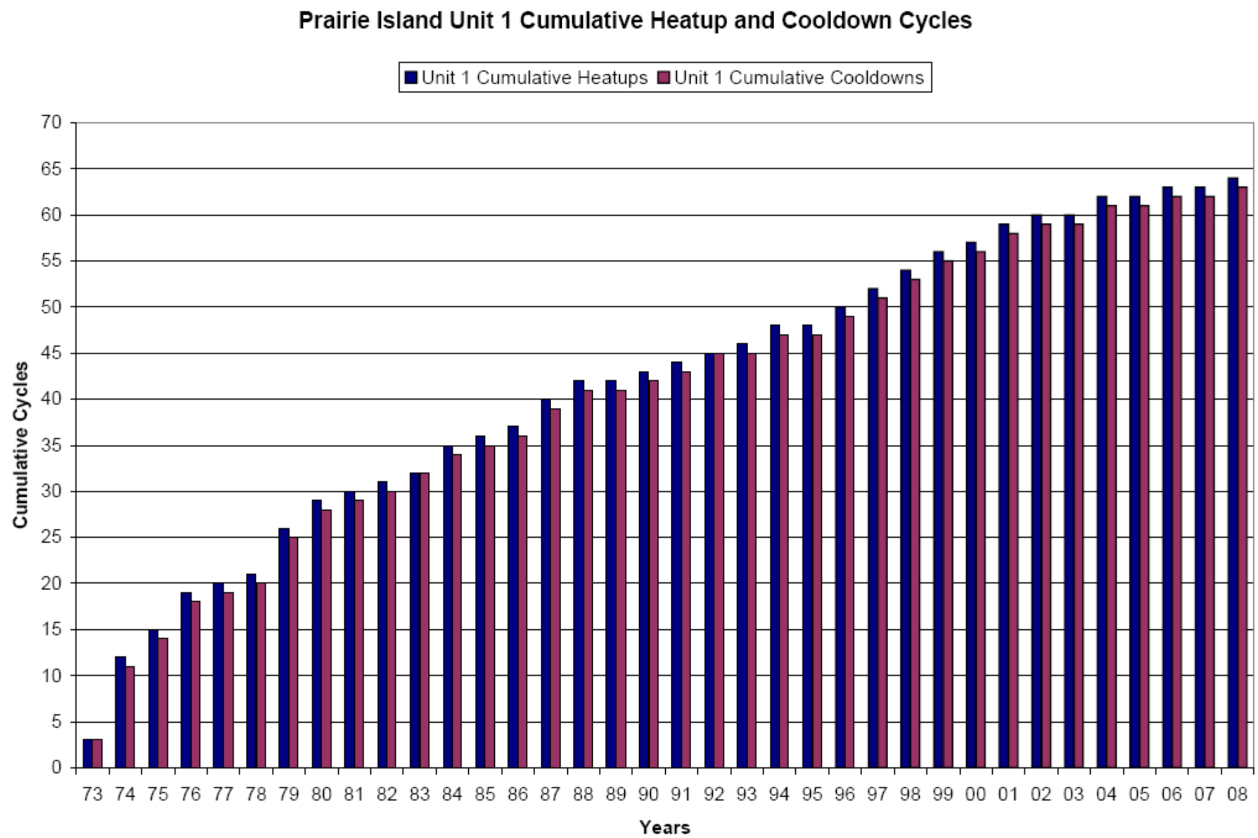
It should be noted that the surveillance procedure does not explicitly state that action should be initiated before a design limit is exceeded. Therefore, as a program enhancement discussed in LRA Section B3.2 (Page B-86), the Metal Fatigue of Reactor Coolant Pressure Boundary Program acceptance criteria will be revised to clarify that corrective action is to be taken before any monitored location exceeds either a cumulative fatigue usage factor of 1.0 or a design basis transient cycle limit.

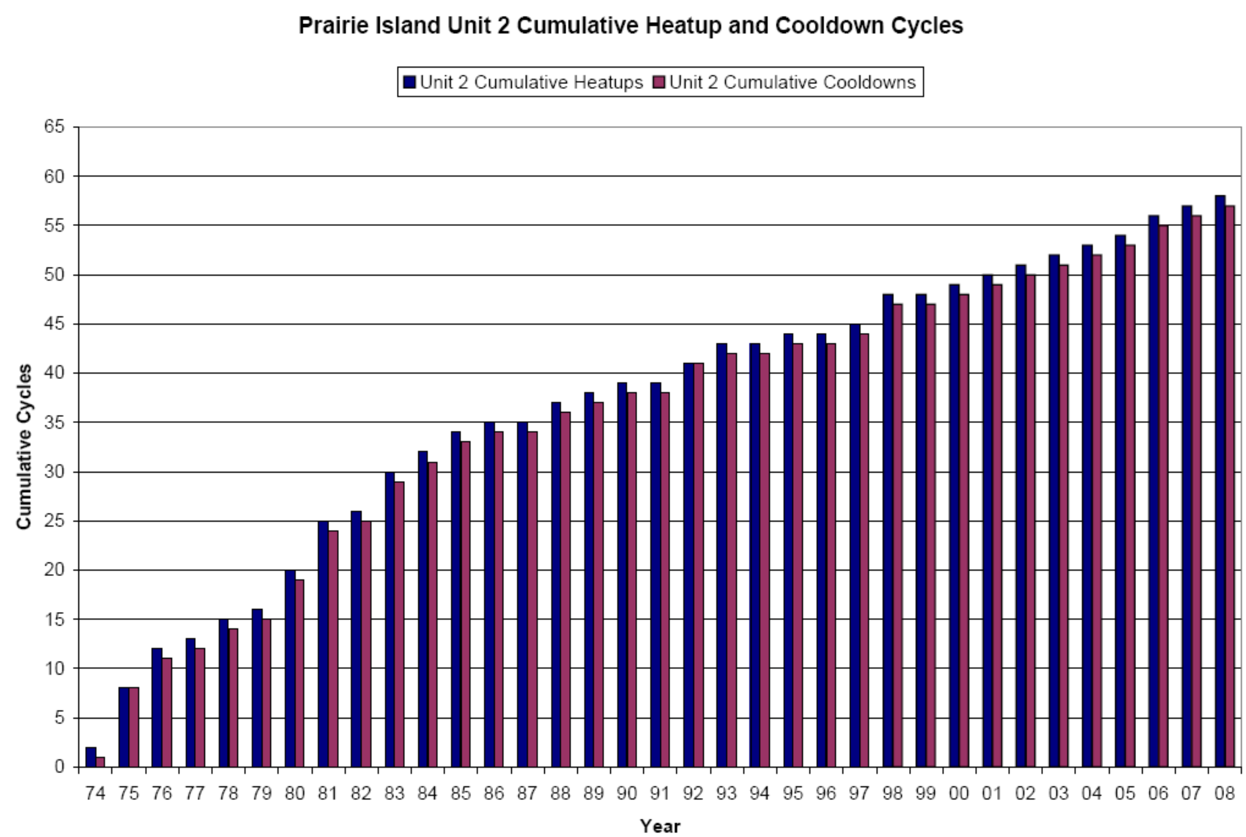
Implementation of the PINGP Metal Fatigue of Reactor Coolant Pressure Boundary Program will ensure that that the Class 1 components are operated within the fatigue design basis defined by the component design specifications for the life of the plant.

Part (b)

Histograms showing the cumulative number of heatup and cooldown cycles for PINGP Units 1 and 2 through 2008 are provided below. Since both Units were operating at the end of 2008, the cumulative number of cooldowns for each Unit is one fewer than the number of heatups.

Enclosure 1
NSPM Responses to NRC Requests for Additional Information
Dated February 20, 2009





Enclosure 2
NSPM Responses to NRC Follow Up Questions

RAI 2.3-01 (2.3.4.5) Follow Up Question

RAI 2.3-01 (2.3.4.5 third bullet) indicated that drawings LR-39222 and LR-39223 Location B-5, shows a continuation of incoming pipe sections (with no identification numbers [Condensate Transfer]) from drawing LR-39220. The NSPM response in a letter dated 12/18/08 stated that the continuation of drawings LR-39222 and LR-39223, location B-5, Condensate Transfer to line 8-DE-56, is shown on drawing LR-39220, location E-2, 2 1/2" Condensate Transfer and Recycle Pump discharge lines connecting to line 8-DE-56 on either side of valve C-41-2. The continuations are located at E-2, however the scoping criterion of pipe sections (out of system dashed lines) don't match the feed lines (from unit 2 condensate storage tank) on drawing LR-39222 which show 10 CFR 54.4 (a)(1) lines to which these (a)(2) lines are connected (B-5). Additional information needed is the location of anchors on drawing LR-39220, location B-5 downstream of valves C-34-2 and C-40-3.

NSPM Response to RAI 2.3-01 (2.3.4.5) Follow Up Question

On drawings LR-39222 and LR-39223, location B-5, the scoping classification of the out of system dashed lines showing the 2 ½" Condensate Transfer lines continuing from LR-39220 are incorrect; the lines should be shown as within the scope of License Renewal per 10 CFR 54.4(a)(3) as shown on drawing LR-39220, location E-2. These lines are within the scope of License Renewal per 10 CFR 54.4(a)(3) and therefore identification of anchors beyond the scoping break at valves C-34-1 and C-34-2 per Scoping Criteria 2 for Non-Safety Related SSCs Directly Connected to Safety Related SSCs is not applicable.

RAI 2.3-01 (2.3.4.6) Follow Up Questions and NSPM Responses

<u>RAI 2.3-01 (2.3.4.6 third bullet)</u>
RAI 2.3-01 (2.3.4.6 third bullet) indicated that drawing LR-39218, locations F-6, G-5, and G-6, pipe sections 10-MS-27, 12-MS-3, 12-MS-4, respectively, show continuations to drawing LR-39233. The NSPM response in a letter dated 12/18/08 stated that the continuation of drawing LR-39218, locations F-6, G-5 and G-6, lines 10-MS-27, 12-MS-3 and 12-MS-4, are shown on drawing LR-39233, location F-1, at valve TD-4-2 (line 10-MS-27) and location B-3, at valves TD-10-1 and TD-10-5 (lines 12-MS-3 and 12-MS-4). The continuation lines were located; however, please confirm the scoping criteria for the out of system dashed lines (10") before valve TD-4-2 in drawing LR-39233.

<u>Response to RAI 2.3-01 (2.3.4.6 third bullet) Follow Up Question</u>: On drawing LR-39233, location F-1, the scoping classification for the out of system dashed lines showing the 10" line and pipe cap before valve TD-4-2 are incorrect; the lines and pipe cap should be shown as within the scope of License Renewal per 10 CFR 54.4(a)(3) as shown on drawing LR-39218, location F-6.

Enclosure 2
NSPM Responses to NRC Follow Up Questions

RAI 2.3-01 (2.3.4.6 fourth bullet)
RAI 2.3-01 (2.3.4.6 fourth bullet) indicated that drawing LR-39219, locations F-6, G-5, and G-6, pipe sections 10-2MS-27, 12-2MS-3, and 12-2MS-4, respectively, show continuations to drawing LR-39234. The NSPM Response in a letter dated 12/18/08 stated that the continuation of drawing LR-39219, locations F-6, G-5 and G-6, lines 10-2MS-27, 12-2MS-3 and 12-2MS-4, are shown on drawing LR-39234, location E-1, at valve 2TD-4-2 (line 10-2MS-27) and location B-3, at valves 2TD-10-1 and 2TD-10-5 (lines 12-2MS-3 and 12-2MS-4). The continuation lines were located; however, please confirm the scoping criteria for the out of system dashed lines (10") before valve 2TD-4-2 in drawing LR-39234.

Response to RAI 2.3-01 (2.3.4.6 fourth bullet) Follow Up Question: On drawing LR-39234, location E-1, the scoping classification for the out of system dashed lines showing the 10” line and pipe cap before valve 2TD-4-2 are incorrect; the lines and pipe cap should be shown as within the scope of License Renewal per 10 CFR 54.4(a)(3) as shown on LR-39219, location F-6.

RAI 2.3-01 (2.3.4.6 fifth bullet)
RAI 2.3-01 (2.3.4.6 fifth bullet) indicated that drawing LR-39218, location D-7, pipe sections 6-MS-31 showed continuations to drawing LR-39233 and drawing LR-39219, location D-7, pipe sections 6-2MS-31 showed a continuation to drawing LR-39234. The NSPM response in a letter dated 12/18/08 stated that the continuation of drawings LR-39218 and LR-39219, location D-7, Drain to Trap, is shown on drawings LR-39233, location C-2, at valve TD-11-1, and LR-39234, location C-2, at valve 2TD-11-1, respectively. The continuations were found, but the scoping criteria of piping section (out of system dashed lines) before valves TD-11-1 and 2TD-11-1 differ between drawings.

Response to RAI 2.3-01 (2.3.4.6 fifth bullet) Follow Up Question: On drawings LR-39233 and LR-39234, location C-2, the scoping classification for the out of system dashed lines showing the 4” and 6” lines and pipe cap before valve TD-11-1 and 2TD-11-1, respectively, are incorrect; the lines and pipe cap should be shown as within the scope of License Renewal per 10 CFR 54.4(a)(3) as shown on LR-39218 and LR-39219, location D-7.

RAI 2.3-01 (2.3.4.6 sixth bullet)
RAI 2.3-01 (2.3.4.6 sixth bullet) indicated that drawing LR-39218, locations E-6 and E-7, pipe sections 3-MS-30, and upstream pipe sections after the valves TD-6-11, TD-6-12 1" "Drains to Trap" showed continuations to drawing LR-39233 and drawing LR-39219, locations E-6 and E-7, pipe sections 3-2MS-30, and upstream pipe sections after the valves 2TD-6-11, 2TD-6-12 showed continuations to drawing LR-39234. The NSPM response in a letter dated 12/18/08 stated that the continuation of drawings LR-39218 and LR-39219, locations E-6 and E-7, Drains to Trap, is shown on drawings LR-39233, location C-3, at valves TD-11-16, TD-6-11 and TD-6-12 and LR-39234, location C-3, at valves 2TD-11-16, 2TD-6-11 and 2TD-6-12. The continuations were located; however the scoping criteria of piping section (out of system dashed lines) before the valves TD-11-16 and 2TD-11-16 should be 10 CFR 54.4 (a)(1) instead of 10 CFR 54.4 (a)(2).

<u>Response to RAI 2.3-01 (2.3.4.6 sixth bullet) Follow Up Question:</u> On drawings LR-39233 and LR-39234, location C-3, the scoping classification for out of system dashed lines showing the 3" line, reducer and motor valves before valve TD-11-16 and 2TD-11-16, respectively, are incorrect; the lines, reducer and motor valves should be shown as within the scope of License Renewal per 10 CFR 54.4(a)(3) as shown on LR-39218 and LR-39219, location E-6.

<u>RAI 2.3-01 (2.3.4.6 eighth bullet)</u>
RAI 2.3-01 (2.3.4.6 eighth bullet) indicated that drawing LR-39218, locations E-8 and H-8, pipe sections 1/2-MS-59 and 12-MS-35, respectively, showed continuations to drawing LR-39233, and LR-39219, locations E-8 and H-8, pipe sections 1/2-2MS-32 and 12-2MS-35, respectively, showed continuations to drawing LR-39234. The NSPM response in a letter dated 12/18/08 stated, in part, that the continuation of drawings LR-39218 and LR-39219, location E-8, 1/2-MS-59 and 1/2-2MS-32, Drain to Trap, are shown on LR-39233 and LR-39234, location C-9, at valve TD-16-1 and 2TD-16-1, respectively. The scoping criteria of the dashed line before valve TD-16-1 on the continuation drawing LR-39233 at location C-9 differs from that on drawing LR-39218.

<u>Response to RAI 2.3-01 (2.3.4.6 eighth bullet) Follow up Question:</u> On drawings LR-39233 and LR-39234, location C-9, the scoping classification for valve TD-16-1 and 2TD-16-1, respectively, and out of system dashed lines showing the upstream ¾" and ½" piping are incorrect; the valves and lines should be shown as within the scope of License Renewal per 10 CFR 54.4(a)(3) as shown on drawing LR-39218, location E-8 (typical). On drawing LR-39219, location E-8, the scoping classification for line 1/2-2MS-32 and the valve shown at the MS/TB system boundary break are incorrect; the line and valve should be shown as within the scope of License Renewal per 10 CFR 54.4(a)(3) similar to the way this same configuration is shown on the Unit 1 drawing LR-39218, location E-8.

<u>RAI 2.3-01 (2.3.4.6 thirteenth bullet)</u>
RAI 2.3-01 (2.3.4.6 thirteenth bullet) indicated that drawings LR-39218 and LR-39219, location F-6, show a continuation of pipe sections 1-1/2-MS-40, 1-1/2-MS-41 and 2-2MS-40, 2-2MS-41 from stop valves of drawings LR-39233 and LR-39234, respectively. The NSPM response in a letter dated 12/18/08 stated that the continuations of drawing LR-39218, location F-6, Drains From Stop Valves, are shown on drawing LR-39233, location A-4, Turb Stop Valve Drains and on drawing LR-XH-2-15, location A-5, Connection 24. The continuations of LR-39219, location F-6, Drains From Stop Valves, are actually connected on drawing LR-39234, location A-4, similar to the Unit 1 drawing; the connections are not explicitly shown. The continuation is also shown on drawing LR-XH-1002-43, locations B-5 and B-6, Connection 24. The continuations were located; however, the scoping criteria of the continuations (as well as the stop valves) on LR-39233 differ. These lines are in scope for 10 CFR 54.4(a)(1). Confirm the scoping classification of these lines on drawing LR-39233.

<u>Response to RAI 2.3-01 (2.3.4.6 thirteenth bullet) Follow up Question:</u> On drawings LR-39233 and LR-39234, location A-4, the scoping classification for the turbine stop valves, and on drawing LR-39233, location A-4, the stop valve 1 ½" drains, are

incorrect; the valves and drains should be shown as within the scope of License Renewal per 10 CFR 54.4(a)(3) as shown on drawings LR-39218 and LR-39219, location F-6.

RAI 3.1.2-02 Follow Up Question

In the 2/10/09 telephone conference, the NRC questioned the ability to reliably detect stress corrosion cracking of Class 1 cast austenitic stainless steel (CASS) piping utilizing an ultrasonic (UT) examination method as discussed in the NSPM Response to RAI 3.1.2-02. The NRC noted that current UT methods have not been qualified to detect cracks in a large-grained CASS microstructure. The NRC requested that NSPM consider the use of an enhanced visual examination for the detection of stress corrosion cracking (SCC) in CASS piping. NSPM agreed to provide a clarification to the original RAI response.

NSPM Response to RAI 3.1.2-02 Follow Up Question

In Part 4 of the NSPM Response to RAI 3.1.2-02 (letter dated 1/20/09), NSPM described the difficulties associated with the ultrasonic examination of cast austenitic stainless steel main coolant pipe welds. The response also included details of examination acceptance criteria used by PINGP to improve the UT inspection of the CASS reactor coolant piping. Although inspection procedures provide a “best effort” examination, NSPM acknowledges that the inspection procedures have not been demonstrated through a program consistent with ASME Section XI, Appendix VIII. In response to the 2/10/09 telephone conference with the NRC, NSPM provides the following clarification, which augments the Response to RAI 3.1.2-02 provided in the NSPM letter dated January 20, 2009.

NSPM acknowledges that current UT examination methods are not adequate for reliable detection of cracks in CASS components. NSPM intends to follow and support the industry initiatives focused on the development of an ultrasonic examination technique that can be demonstrated through a program consistent with ASME Section XI, Appendix VIII.

As shown in LRA Table 3.1.2-2, PINGP credits the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program (IWB, IWC, and IWD Program) to manage cracking due to SCC of the Class 1 CASS piping. The IWB, IWC, and IWD Program is implemented in accordance with the requirements of 10 CFR 50.55a, with specified limitations, modifications and NRC-approved alternatives, and applicable provisions of ASME Section XI. During the period of extended operation, should the PINGP IWB, IWC, and IWD Program, with NRC-approved alternatives, require volumetric examinations to be performed per ASME Section XI, Table IWB-2500-1, Examination Category B-J, on the Class 1 cast austenitic stainless steel main coolant pipe welds, then an ultrasonic examination method qualified under ASME Section XI, Appendix VIII will be utilized or an NRC-approved alternative (e.g., enhanced visual examination) will be implemented.

Section 3.1.2.2.13 Follow Up Question

LRA Further Evaluation Section 3.1.2.2.13 says it addresses nickel alloy in reactor internals, but the section is intended to address all nickel alloy in the RCS. Internals are addressed in SRP Sections 3.1.2.2.15 and 17. Correction or clarification is needed.

NSPM Response to Section 3.1.2.2.13 Follow Up Question

The further evaluation of cracking due to primary water stress corrosion cracking (PWSCC) contained in LRA Section 3.1.2.2.13 incorrectly refers to this aging effect/mechanism occurring in reactor vessel internals components. The associated Table 1 Item Number 3.1.1-31 is used in LRA Table 3.1.2-1, Pressurizer System – Summary of Aging Management Evaluation, and Table 3.1.2-4, Reactor Vessel System – Summary of Aging Management Evaluation. Therefore this further evaluation should refer to this aging effect/mechanism occurring in pressurizer and reactor vessel components. The first sentence of LRA Section 3.1.2.2.13 is hereby deleted and replaced with the following:

Cracking due to primary water stress corrosion cracking could occur for nickel alloy pressurizer and reactor vessel components.

Cracking due to primary water stress corrosion cracking for nickel alloy reactor internals components is evaluated under Table 1 Item Number 3.1.1-37 and in LRA Section 3.1.2.2.17.

RAI 3.3.2.2.4.1-01 Follow Up Question

The NSPM response to RAI 3.3.2.2.4.1-01 in a letter dated 1/20/2009 indicates that aging of the regenerative and non-regenerative heat exchangers is managed by the Water Chemistry and One-Time Inspection Programs. NRC indicated that use of Water Chemistry and One-Time Inspection for management of SCC is acceptable. However, the aging effect/mechanism of cracking due to cyclic loading in GALL would not be managed by these programs. The RAI dispositions cyclic loading by reference to a TLAA, but there is not a full analysis of fatigue in heat exchanger tubes, so the aging effect is not really being managed as a TLAA. One-time inspection of other components of the same materials and environment would not be representative of the unique cyclic loading experienced in the heat exchanger. NSPM indicated in the 2/10/09 telephone conference that cyclic loading is not an applicable aging mechanism for these heat exchangers and agreed to provide a discussion that shows why cyclic loading is not applicable.

NSPM Response to RAI 3.3.2.2.4.1-01 Follow Up Question

Part 1 of the NSPM Response to RAI 3.3.2.2.4.1-01 (1/20/09 letter) is hereby revised in its entirety. Note that Parts 2 - 6 of the original RAI response are unaffected, and remain as originally submitted. The revised Part 1 is as follows:

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. The combination of the Water Chemistry Program and the One-Time Inspection Program provides reasonable assurance that cracking due to SCC will be adequately managed for the Regenerative Heat Exchangers and non-regenerative heat exchangers (Letdown Heat Exchangers and Excess Letdown Heat Exchangers).

Cracking due to cyclic loading is not an applicable aging mechanism given the design and operation of the regenerative and non-regenerative heat exchangers at PINGP. Although a full fatigue analysis was not required for these heat exchangers, the Westinghouse design specification for these components included requirements to demonstrate that the heat exchangers satisfied all conditions of ASME Section III, Paragraph N-415.1, “Vessels Not Requiring Analysis for Cyclic Operation,” for the transient conditions specified. Through compliance with N-415.1 (a) through (f), which considers pressure fluctuations, thermal cycling, and mechanical loading, the peak stress limit discussed in Paragraph N-414.5 is satisfied for these heat exchangers, and an analysis for cyclic operation is not required. Therefore, from a design standpoint the Regenerative Heat Exchangers, Letdown Heat Exchangers, and Excess Letdown Heat Exchangers are not subject to cracking due to cyclic loading.

Additionally, a review of operating history did not reveal any degradation of the heat exchanger components (refer to Part 4 of the original RAI response for further discussion). The Regenerative Heat Exchangers and Letdown Heat Exchangers typically remain in service throughout the entire operating cycle. The Excess Letdown Heat Exchanger is normally isolated during plant operation and is put in service when the normal letdown path is not available. As a result, the heat exchangers are not subject to repeated thermal and pressure cycling. The heat exchangers have not experienced problems due to vibration. Generally, failure due to vibration is expected to be detected early in component service life, and is not considered an aging effect for the period of extended operation. Therefore, from an operational standpoint, cracking due to cyclic loading does not apply to these heat exchangers.

As illustrated above, the design and operation of the Regenerative Heat Exchangers, Letdown Heat Exchangers, and Excess Letdown Heat Exchangers preclude cyclic loading from being an aging mechanism requiring aging management during the period of extended operation. The following LRA changes are hereby made in order to reflect that cracking due to cyclic loading is not applicable to the regenerative and non-regenerative heat exchangers at PINGP.

In LRA Table 3.3.1 (Page 3.3-45), Summary of Aging Management Evaluations in Chapter VII of NUREG-1801 for Auxiliary Systems, Item Number 3.3.1-07 is hereby replaced in its entirety as shown below:

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-07	Stainless steel non-regenerative heat exchanger components exposed to treated borated water >60°C (>140°F)	Cracking due to stress corrosion cracking and cyclic loading	Water Chemistry and a plant-specific verification program. An acceptable verification program is to include temperature and radioactivity monitoring of the shell side water, and eddy current testing of tubes.	Yes, plant specific	The plant-specific AMP that manages cracking due to stress corrosion cracking of stainless steel non-regenerative heat exchanger components exposed to treated borated water >60°C (>140°F) in addition to the Water Chemistry Program is the One-Time Inspection Program. Cracking due to cyclic loading is not an applicable aging mechanism. Further evaluation is documented in Section 3.3.2.2.4.1.

In LRA Table 3.3.1 (Page 3.3-45), Summary of Aging Management Evaluations in Chapter VII of NUREG-1801 for Auxiliary Systems, Item Number 3.3.1-08 is hereby replaced in its entirety as shown below:

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-08	Stainless steel regenerative heat exchanger components exposed to treated borated water >60°C (>140°F)	Cracking due to stress corrosion cracking and cyclic loading	Water Chemistry and a plant-specific verification program. The AMP is to be augmented by verifying the absence of cracking due to stress corrosion cracking and cyclic loading. A	Yes, plant specific	The plant-specific AMP that manages cracking due to stress corrosion cracking of stainless steel regenerative heat exchanger components exposed to treated borated water >60°C (>140°F) in addition to the Water Chemistry Program is the One-Time Inspection Program. Cracking due to cyclic loading is not an applicable

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
			plant specific aging management program is to be evaluated.		aging mechanism. Further evaluation is documented in Section 3.3.2.2.4.2.

In LRA Section 3.3.2.2.4 (Pages 3.3-34 and 3.3-35), under Cracking due to Stress Corrosion Cracking and Cyclic Loading, Items 1 and 2 are revised in their entirety to read as follows:

1. Cracking due to stress corrosion cracking could occur in stainless steel non-regenerative heat exchanger components exposed to treated water greater than 140°F. This aging effect is managed with a combination of the Water Chemistry Program and the One-Time Inspection Program. Cracking due to cyclic loading is not an applicable aging mechanism since the non-regenerative heat exchanger components were designed to adequately cope with the stresses induced by cyclic loading, which precluded the need for a detailed analysis for cyclic operation.

   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 One-Time Inspection Program performs sampling inspections using nondestructive examination techniques that either verify unacceptable degradation is not occurring or trigger additional actions. These programs assure the intended function of affected components will be maintained during the period of extended operation. The One-Time Inspection Program is selected in lieu of temperature and radioactivity monitoring of the shell side water and eddy current testing of tubes.

   This position was found acceptable to the NRC staff in NUREG-1785, Safety Evaluation Report Related to the License Renewal of H. B. Robinson Steam Electric Plant, Unit 2. Section 3.3.2.2.8 of the applicant's Safety Evaluation Report states:

   > “In LRA Table 3.3-1, row 8 the applicant stated that stress corrosion cracking (SCC) is an applicable aging mechanism for the seal water, excess letdown, and regenerative heat exchangers.
   >
   > The applicant credited the Water Chemistry Program for managing the crack initiation and growth due to SCC in these heat exchangers and the

Closed-Cycle Cooling Water System Program for managing the aging effect for heat exchangers cooled by the CCW system. To verify the effectiveness of the Water Chemistry Program in preventing cracking due to SCC, the applicant credited an inspection of small-bore Class 1 piping system and components connected to the RCS under the One-Time Inspection Program in selected locations where degradation would be expected. The applicant stated that management of SCC for this group is consistent with the GALL Report with the exception that the onetime inspection will be used instead of the eddy current testing recommended in the GALL Report. The Water Chemistry Program and the One-Time Inspection Program are evaluated in Sections 3.0.3.3 and 3.0.3.9 of this SER. The staff finds that these programs can effectively manage the cracking initiation and growth due to SCC for the above components that are applicable to RNP auxiliary systems.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of crack initiation and growth due to SCC and cyclic loading for components in the auxiliary systems, as recommended in the GALL Report. On the basis of this finding, and the finding that the remainder of the applicant's program is consistent with GALL, the staff concludes that the applicant has demonstrated that these aging effects will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation."

2. Cracking due to stress corrosion cracking could occur in stainless steel regenerative heat exchanger components exposed to treated water greater than 140°F. This aging effect is managed with a combination of the Water Chemistry Program and the One-Time Inspection Program. Cracking due to cyclic loading is not an applicable aging mechanism since the regenerative heat exchanger components were designed to adequately cope with the stresses induced by cyclic loading, which precluded the need for a detailed analysis for cyclic operation. See Section 3.3.2.2.4.1 for additional details.

Section 3.3.2.2.12.2 Follow Up Question

The applicant states in LRA Section 3.3.2.2.12.2 that MIC of stainless steel piping, piping components, and piping elements exposed to a lubricating oil environment is not managed based on operating experience. Operating experience alone is not justification for eliminating management of an aging mechanism. Provide plant-specific operating history that indicates MIC is not active. Provide additional information, including inspection results of weld heat affected zones, that demonstrates stainless steel piping, piping components and piping elements are not subject to MIC when exposed to lubricating oil.

NSPM Response to Section 3.3.2.2.12.2 Follow Up Question

Microbiologically Influenced Corrosion (MIC) is facilitated by stagnant conditions, fouling, internal crevices, contact with untreated water, and contact with contaminated soils. While MIC contamination is possible in lubricating oil applications, the likelihood of MIC causing extensive damage in lube oil systems is minimal. Even if contamination of the oil occurs, the relatively clean systems and addition of corrosion inhibitors to the lubrication oil does not provide an environment conducive to microorganism growth. The potential for MIC growth and subsequent corrosion effects in lube oil systems are very small based on the addition of lube oil corrosion additives, oil purity testing programs, and the low likelihood of lube oil contamination. Even if MIC were to be introduced into these systems, which would be event-driven as opposed to age related, sampling programs would detect and correct the situation prior to MIC causing any appreciable corrosion of lubricating oil system components. Review of industry failure data, generic communications, and plant-specific operating experience confirm that MIC is not expected to occur in lubricating oil systems unless external contamination of the lubricating oil has occurred (event driven). Therefore, MIC is not considered to be an applicable aging mechanism in lubricating oil systems.

The following changes are hereby made to the LRA.

In LRA section 3.3.2.2.9.2 on Page 3.3-39, the second sentence is deleted and replaced with the following:

> PINGP excludes loss of material due to fouling or microbiologically influenced corrosion in a lubricating oil environment based upon an evaluation of the materials of construction and operating environment, along with industry and plant specific operating experience.

In LRA section 3.3.2.2.12.2 on Page 3.3-42, the second sentence is deleted and replaced with the following:

> PINGP excludes loss of material due to microbiologically influenced corrosion in a lubricating oil environment based upon an evaluation of the materials of construction and operating environment, along with industry and plant specific operating experience.

In LRA section 3.4.2.2.5.2 on Page 3.4-17, the following new sentence is inserted immediately after the existing first sentence:

> PINGP excludes loss of material due to microbiologically influenced corrosion in a lubricating oil environment based upon an evaluation of the materials of construction and operating environment, along with industry and plant specific operating experience.

In LRA Section 3.4.2.2.8 on Page 3.4-20, the following new sentence is inserted immediately after the existing first sentence:

> PINGP excludes loss of material due to microbiologically influenced corrosion in a lubricating oil environment based upon an evaluation of the materials of construction and operating environment, along with industry and plant specific operating experience.

Table 3.4.2-4 Follow Up Question

NRC requested clarification on a line item in LRA Table 3.4.2-4 on page 3.4-75 for Flex Connections of Stainless Steel in an Outdoor Air - Sheltered environment. The line item has Note G (environment not in GALL) but points to a GALL Table 1 line for Indoor Air - Uncontrolled. Reviewer asked what the external environment actually is.

NSPM Response to Table 3.4.2-4 Follow Up Question

LRA Table 3.4.2-4 (page 3.4-75) shows stainless steel flex connections exposed to an environment of outdoor air – sheltered (ext). These components are outdoors and are insulated and jacketed (i.e., sheltered). The insulation and jacket protect (shelter) the components from precipitation. The humidity experienced in an outdoor air – sheltered environment would be equivalent to that in an indoor air – uncontrolled environment. Therefore, the environment is equivalent to plant indoor air – uncontrolled and has been evaluated using GALL Volume 2 line item VIII.I-10 (GALL Volume 1 line item 3.4.1-41) with Note G which states, "Environment is not in NUREG-1801 for this component and material." Alternatively, Note A coupled with Note 419 could have been used. Note 419 states, "The environment for this line item is equivalent to Plant Indoor Air – Uncontrolled with the potential for moisture or condensation." For example, see LRA Table 3.4.2-4 (page 3.4-87), stainless steel valves exposed to an environment of outdoor air – sheltered (ext). Both Note G and Note A coupled with Note 419 are correct.

B2.1.9 Follow Up Question

The new Closed-Cycle Cooling Water System Program exception identified in the letter dated 2/6/09 indicated that no performance testing is conducted on three chiller loops, and that aging management is being performed with water chemistry control under the CCCW System Program. This is not sufficient to tell whether aging is occurring. NSPM agreed to modify the exception to clarify that visual inspections will be performed on the three chiller loops affected by the exception.

NSPM Response to B2.1.9 Follow Up Question

In LRA Section B2.1.9, under Exceptions to NUREG-1801 (Pages B-27 and B-28), a third bullet is hereby added to read as follows. Note that the following text replaces, in its entirety, the text of the exception previously provided in the February 6, 2009 letter.

- Detection of Aging Effects

  No periodic performance testing is conducted on the Cold Lab Chiller Loop, Computer Room Chiller Loop, or Hot Lab Chiller Loop as recommended by NUREG-1801. Periodic visual inspections will be performed on these systems to identify the presence of aging effects and to confirm the effectiveness of chemistry controls. The coolant environment in these chiller loops is managed by periodic sampling and chemistry control. Chemical controls and visual inspections are adequate to manage aging effects in these closed-cycle cooling water systems.

B2.1.19 Follow Up Question

In the telephone conference of 2/10/09, the NRC noted that PINGP has taken an exception to the GALL recommendation for monitoring of fuel oil for biological activity. In lieu of specific biological testing, the NRC requested clarification as to the type of testing that is performed that would detect the presence of biological activity in fuel oil. Additionally, the NRC requested clarification on the use of ASTM Standard D 975 in the PINGP Fuel Oil Chemistry Program.

NSPM Response to B2.1.19 Follow Up Question

As stated in the NSPM Response to RAI B2.1.19-2 (12/18/08 letter), PINGP does not monitor fuel oil for biological activity. Fuel oil samples have not shown cloudiness, sludge, or other conditions that would indicate significant biological activity or fuel degradation. The PINGP Fuel Oil Chemistry Program performs water and sediment testing in accordance with ASTM Standard D 1796. Particulate contamination testing is performed in accordance with ASTM Standard D 6217. Use of these standards is consistent with those recommended in NUREG-1801, Program XI.M30, Elements 1 and 6. ASTM D 1796 uses a centrifuge test method to measure the volume of water and sediment in fuel oil. ASTM D 6217 assesses the mass quantity of particulate contamination present in fuel oil by filtration using a conservative filter pore size of 0.8 μm. Since biological activity would produce sludge and other by-products of metabolism, the test results for water and sediment (reported in volume percent) and particulate contamination (reported in mass per volume of fuel filtered) would identify the presence of biological activity in the fuel oil. Test results would exhibit an increase if biological activity were present. The program acceptance criterion for water and sediment content is 0.05 % (max.) and the acceptance criterion for particulate contamination is 20 mg/L (max.).

NUREG-1801, Program XI.M30, Fuel Oil Chemistry, Element 1 states, “The program is focused on managing the conditions that cause general, pitting, and microbiologically-influenced corrosion (MIC) of the diesel fuel tank internal surfaces in accordance with the plant’s technical specifications…” As required by PINGP Technical Specifications, Section 5.5.11, “The program shall include sampling and testing requirements, and acceptance criteria, all in accordance with the limits specified in Table 1 of ASTM D 975-77 when checked for viscosity, water, and sediment.” Therefore, consistent with NUREG-1801 and plant Technical Specifications, the PINGP Fuel Oil Chemistry Program utilizes the requirements of ASTM Standard D 975-77 to prescribe the required properties of fuel oil in use at PINGP.

February 26, 2009

L-PI-09-030
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 February 20, 2009 and Follow Up Questions 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 February 20, 2009, the NRC transmitted Requests for Additional Information (RAIs) regarding that application. Enclosure 1 of this letter provides the text of each RAI followed by the NSPM response.

NSPM letters dated December 18, 2008, and January 9, January 20 and February 6, 2009, among others, provided responses to Requests for Additional Information (RAIs) concerning the application. In conference calls on February 3, 2009, February 10, 2009 and February 11, 2009, the NRC raised follow up questions about the LRA and certain of those RAI responses. Enclosure 2 of this letter provides a summary of each follow up question followed by the NSPM response.

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 or revisions to existing commitments.

I declare under penalty of perjury that the foregoing is true and correct.
Executed on February 26, 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 February 20, 2009

RAI AMR-3.3.2.9-2

In License Renewal Application (LRA) Table 3.3.2-9, pages 3.3-198, 199 and 200, fire protection system, for copper alloy heat exchanger components and heat exchanger tubes in an internal environment of raw water, PINGP has credited the Fire Water System Program to manage the aging effects loss of material and heat transfer degradation. These lines reference footnote E, and NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," Revision 1, item VII.C1-3. The GALL Report item recommends AMP XI.M20, Open-Cycle Cooling Water Program to manage these aging effects for heat exchangers. The GALL AMP recommends chemical treatment whenever the potential for biofouling species exists as part of the preventive actions and a test program to verify heat transfer capabilities.

Please justify why Open-Cycle Cooling Water System Program is not used.

NSPM Response to RAI AMR-3.3.2.9-2

The Fire Water System Program is used in lieu of the Open-Cycle Cooling Water System Program to manage aging of Fire Protection (FP) System components that are exposed to a raw water environment other than open-cycle cooling water. For LRA Table 3.3.2-9, Auxiliary Systems - Fire Protection System – Summary of Aging Management Evaluation, on Pages 3.3-198, 199 and 200, for copper alloy heat exchanger components and heat exchanger tubes in an internal environment of raw water, the components are exposed to untreated Mississippi River (ultimate heat sink) water. Although the Mississippi River (ultimate heat sink) is the source for both the Cooling Water (CL) System and the FP System, these FP System components are supplied by the Fire Water sub-system which is not managed by the Open-Cycle Cooling Water System Program. Therefore, PINGP has appropriately credited the Fire Water System Program.

In addition, the affected components, 121 Motor Driven Fire Pump Enclosure Cooler and the 122 Diesel Driven Fire Pump Heat Exchanger, are not safety related components and are not within the scope of NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment." Preventive actions associated with the PINGP Fire Water System Program include periodic flushing, performance testing, and inspections. Heat transfer degradation of the 121 Motor Driven Fire Pump Enclosure Cooler is managed by periodic inservice flushing during the 121 Motor Driven Fire Pump Performance Test. Heat transfer degradation of the 122 Diesel Driven Fire Pump Heat Exchanger is managed by periodically monitoring and recording the engine operating temperature during the 122 Diesel Driven Fire Pump Performance Test.

RAI 4.3.1-1

The Prairie Island Nuclear Generating Plant (PINGP) metal fatigue of reactor coolant pressure boundary management program relies on transient cycle monitoring to evaluate the fatigue usage described in the license renewal application. This approach tracks the number of occurrences of significant thermal and pressure transients (significant events) and compares the cumulative cycles, projected to cover the renewal period, against the number of design cycles specified in the design specifications. The projected cycles are then used to evaluate the total cumulative usage factor (CUF) which covers the period of extended operation. For this approach to work, none of the significant events tracked should produce stresses greater than those that would be produced by the design transients. That is, the P-T (Pressure and Temperature) characteristics, including their values, ranges, and rates, all must be bounded within those defined in the design specifications.

(a) Please describe the procedures that PINGP has been using for tracking thermal activities so the staff can confirm that the PINGP aging management program will ensure that P-T characteristics, including their values, ranges, and rates remain bounded within the range defined in the design specifications during the renewed license term.

(b) Please provide a histogram (cycle accumulating charts) of heatup transient history, and a histogram for the cooldown transient as well.

NSPM Response to RAI 4.3.1-1

Part (a):

The significant thermal and pressure transients used to calculate cumulative usage factors are defined in the design specifications for each Class 1 component. These design transients are described in Section 4.1.4 and Table 4.1-8 of the PINGP USAR, and are also provided in Table 4.3-1 of the PINGP LRA. The number of occurrences of design cycles is tracked by the Metal Fatigue of Reactor Coolant Pressure Boundary Program as described in Section B3.2 of the PINGP LRA.

PINGP Technical Specifications Section 5.5.5 establishes the requirement to track the USAR Section 4.1.4 cyclic and transient occurrences to ensure that components are maintained within the design limits. This requirement is implemented by a PINGP surveillance procedure. The procedure requires that records be kept of the applicable thermal and pressure transients. These records are maintained as on-going transient summary sheets contained in the procedure itself.

The PINGP surveillance procedure lists the design pressure and temperature transients from USAR Section 4.1.4, and contains a summary sheet for each design transient which lists every cycle counted for that transient. At least once each quarter, the program owner conducts a review of plant operating records to determine if an “operating cycle” has occurred for any of the design pressure or temperature transients. If a cycle has occurred, the program owner will add the event to the proper cycle summary sheet along with a brief description of the transient cycle. The majority of transient cycles logged to date have been associated with heatups, cooldowns and reactor trip events.

For heatups and cooldowns, the maximum hourly rate (^{o}F/hr) is recorded on the cycle summary sheet for each heatup and cooldown. A review of past plant heatup and cooldown data indicates that the average plant heatup rate has been approximately 40 ^{o}F/hr and the average plant cooldown rate has been about 70 ^{o}F/hr. For design purposes, the transient parameters response for the heatup and cooldown transients is based on a rate of 100 ^{o}F/hr. Therefore, the design transient responses remain bounding with respect to the actual plant heatup and cooldown rates.

For reactor trip events, the initial reactor power level is recorded on the cycle summary sheet. Approximately 65% of the reported reactor trip events in both units have occurred from an initial power level between 75% and 100% power. The remaining 35% of reactor trip events occurred from an initial power level lower than 75% of full power. For design purposes, the reactor trip transient is based on a trip from 100% power conditions. Therefore, the design transient responses remain bounding with respect to the actual plant reactor trip events.

If a design limit for the number or severity of a transient were exceeded (e.g., RCS exceeds 100 ^{o}F/hr during heatup or cooldown), a CAP would be initiated, and the procedure requires that an analysis be performed to determine the effect on system components. The Corrective Action Program would determine appropriate actions, potentially including reanalysis, repair, or replacement of the affected components, and assessment of additional pressure boundary locations that may be affected.

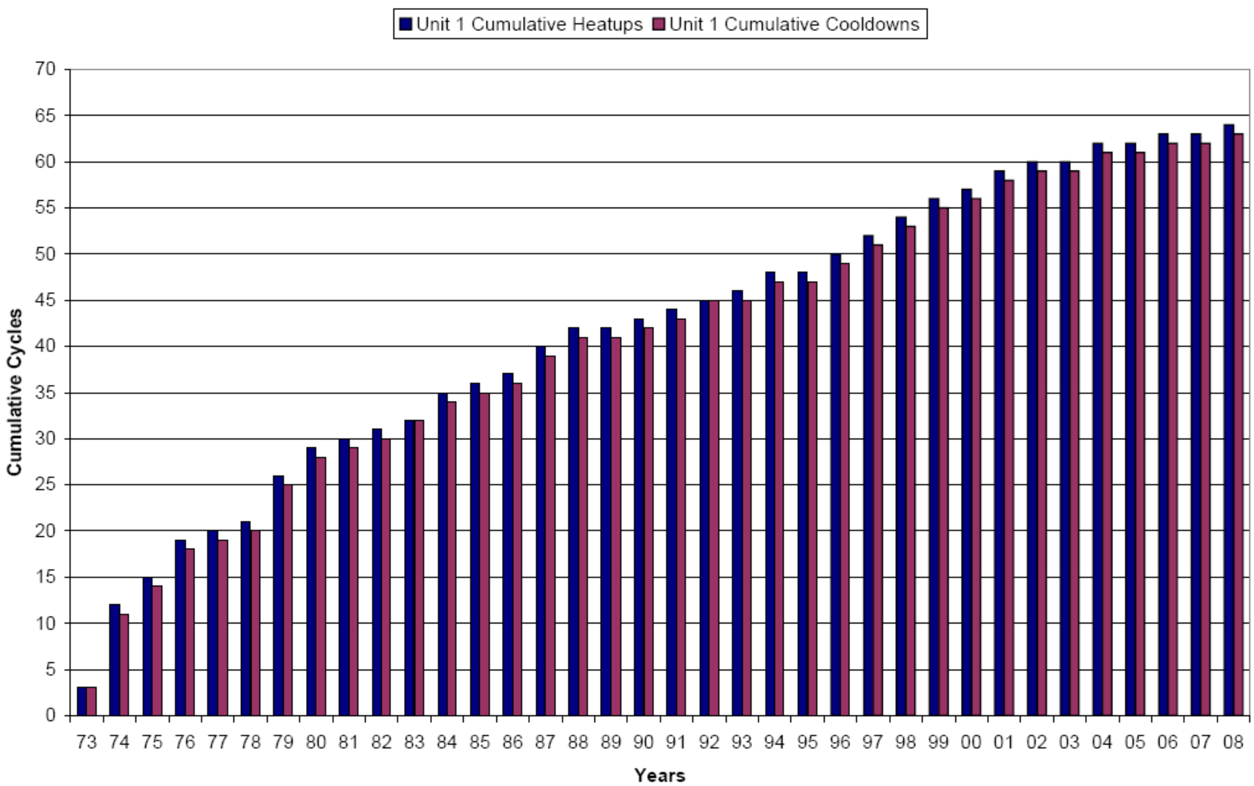
It should be noted that the surveillance procedure does not explicitly state that action should be initiated before a design limit is exceeded. Therefore, as a program enhancement discussed in LRA Section B3.2 (Page B-86), the Metal Fatigue of Reactor Coolant Pressure Boundary Program acceptance criteria will be revised to clarify that corrective action is to be taken before any monitored location exceeds either a cumulative fatigue usage factor of 1.0 or a design basis transient cycle limit.

Implementation of the PINGP Metal Fatigue of Reactor Coolant Pressure Boundary Program will ensure that that the Class 1 components are operated within the fatigue design basis defined by the component design specifications for the life of the plant.

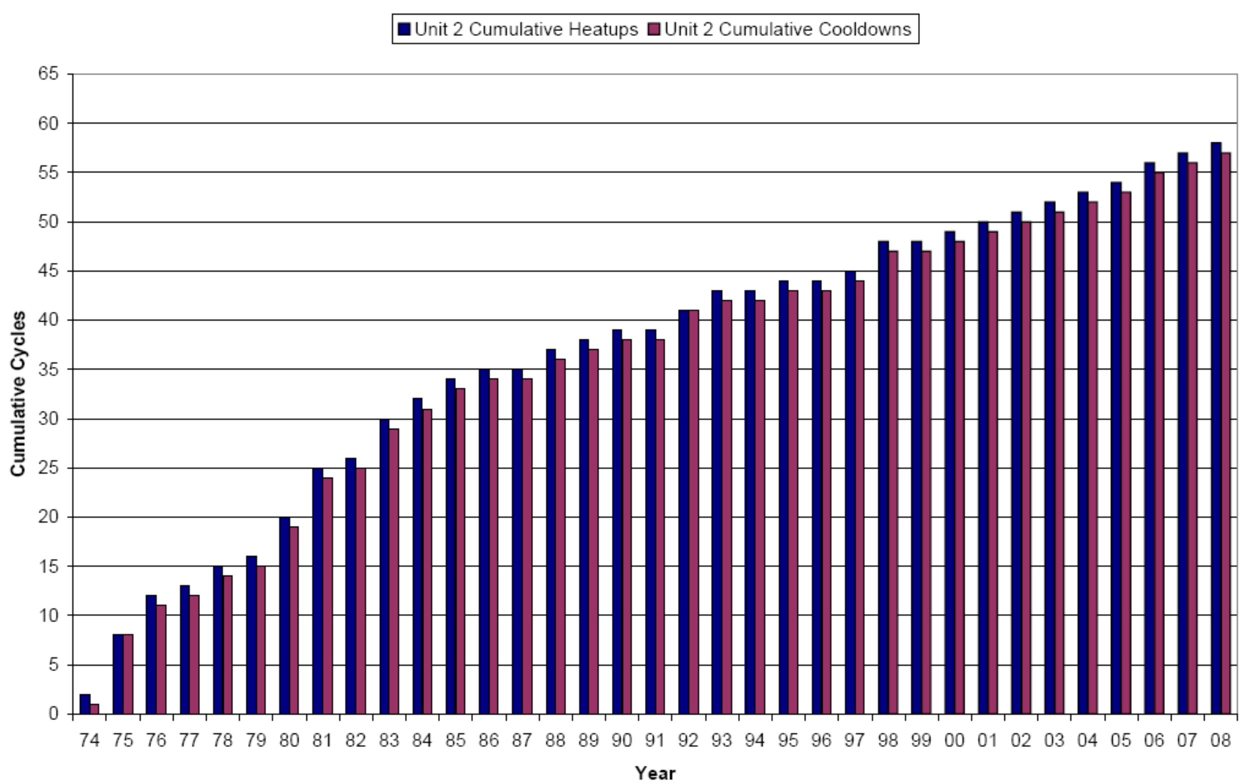
Part (b)

Histograms showing the cumulative number of heatup and cooldown cycles for PINGP Units 1 and 2 through 2008 are provided below. Since both Units were operating at the end of 2008, the cumulative number of cooldowns for each Unit is one fewer than the number of heatups.

Prairie Island Unit 1 Cumulative Heatup and Cooldown Cycles



Prairie Island Unit 2 Cumulative Heatup and Cooldown Cycles



Enclosure 2
NSPM Responses to NRC Follow Up Questions

RAI 2.3-01 (2.3.4.5) Follow Up Question

RAI 2.3-01 (2.3.4.5 third bullet) indicated that drawings LR-39222 and LR-39223 Location B-5, shows a continuation of incoming pipe sections (with no identification numbers [Condensate Transfer]) from drawing LR-39220. The NSPM response in a letter dated 12/18/08 stated that the continuation of drawings LR-39222 and LR-39223, location B-5, Condensate Transfer to line 8-DE-56, is shown on drawing LR-39220, location E-2, 2 1/2" Condensate Transfer and Recycle Pump discharge lines connecting to line 8-DE-56 on either side of valve C-41-2. The continuations are located at E-2, however the scoping criterion of pipe sections (out of system dashed lines) don't match the feed lines (from unit 2 condensate storage tank) on drawing LR-39222 which show 10 CFR 54.4 (a)(1) lines to which these (a)(2) lines are connected (B-5). Additional information needed is the location of anchors on drawing LR-39220, location B-5 downstream of valves C-34-2 and C-40-3.

NSPM Response to RAI 2.3-01 (2.3.4.5) Follow Up Question

On drawings LR-39222 and LR-39223, location B-5, the scoping classification of the out of system dashed lines showing the 2 ½" Condensate Transfer lines continuing from LR-39220 are incorrect; the lines should be shown as within the scope of License Renewal per 10 CFR 54.4(a)(3) as shown on drawing LR-39220, location E-2. These lines are within the scope of License Renewal per 10 CFR 54.4(a)(3) and therefore identification of anchors beyond the scoping break at valves C-34-1 and C-34-2 per Scoping Criteria 2 for Non-Safety Related SSCs Directly Connected to Safety Related SSCs is not applicable.

RAI 2.3-01 (2.3.4.6) Follow Up Questions and NSPM Responses

<u>RAI 2.3-01 (2.3.4.6 third bullet)</u>
RAI 2.3-01 (2.3.4.6 third bullet) indicated that drawing LR-39218, locations F-6, G-5, and G-6, pipe sections 10-MS-27, 12-MS-3, 12-MS-4, respectively, show continuations to drawing LR-39233. The NSPM response in a letter dated 12/18/08 stated that the continuation of drawing LR-39218, locations F-6, G-5 and G-6, lines 10-MS-27, 12-MS-3 and 12-MS-4, are shown on drawing LR-39233, location F-1, at valve TD-4-2 (line 10-MS-27) and location B-3, at valves TD-10-1 and TD-10-5 (lines 12-MS-3 and 12-MS-4). The continuation lines were located; however, please confirm the scoping criteria for the out of system dashed lines (10") before valve TD-4-2 in drawing LR-39233.

<u>Response to RAI 2.3-01 (2.3.4.6 third bullet) Follow Up Question</u>: On drawing LR-39233, location F-1, the scoping classification for the out of system dashed lines showing the 10" line and pipe cap before valve TD-4-2 are incorrect; the lines and pipe cap should be shown as within the scope of License Renewal per 10 CFR 54.4(a)(3) as shown on drawing LR-39218, location F-6.

Enclosure 2
NSPM Responses to NRC Follow Up Questions

RAI 2.3-01 (2.3.4.6 fourth bullet)
RAI 2.3-01 (2.3.4.6 fourth bullet) indicated that drawing LR-39219, locations F-6, G-5, and G-6, pipe sections 10-2MS-27, 12-2MS-3, and 12-2MS-4, respectively, show continuations to drawing LR-39234. The NSPM Response in a letter dated 12/18/08 stated that the continuation of drawing LR-39219, locations F-6, G-5 and G-6, lines 10-2MS-27, 12-2MS-3 and 12-2MS-4, are shown on drawing LR-39234, location E-1, at valve 2TD-4-2 (line 10-2MS-27) and location B-3, at valves 2TD-10-1 and 2TD-10-5 (lines 12-2MS-3 and 12-2MS-4). The continuation lines were located; however, please confirm the scoping criteria for the out of system dashed lines (10") before valve 2TD-4-2 in drawing LR-39234.

Response to RAI 2.3-01 (2.3.4.6 fourth bullet) Follow Up Question: On drawing LR-39234, location E-1, the scoping classification for the out of system dashed lines showing the 10" line and pipe cap before valve 2TD-4-2 are incorrect; the lines and pipe cap should be shown as within the scope of License Renewal per 10 CFR 54.4(a)(3) as shown on LR-39219, location F-6.

RAI 2.3-01 (2.3.4.6 fifth bullet)
RAI 2.3-01 (2.3.4.6 fifth bullet) indicated that drawing LR-39218, location D-7, pipe sections 6-MS-31 showed continuations to drawing LR-39233 and drawing LR-39219, location D-7, pipe sections 6-2MS-31 showed a continuation to drawing LR-39234. The NSPM response in a letter dated 12/18/08 stated that the continuation of drawings LR-39218 and LR-39219, location D-7, Drain to Trap, is shown on drawings LR-39233, location C-2, at valve TD-11-1, and LR-39234, location C-2, at valve 2TD-11-1, respectively. The continuations were found, but the scoping criteria of piping section (out of system dashed lines) before valves TD-11-1 and 2TD-11-1 differ between drawings.

Response to RAI 2.3-01 (2.3.4.6 fifth bullet) Follow Up Question: On drawings LR-39233 and LR-39234, location C-2, the scoping classification for the out of system dashed lines showing the 4" and 6" lines and pipe cap before valve TD-11-1 and 2TD-11-1, respectively, are incorrect; the lines and pipe cap should be shown as within the scope of License Renewal per 10 CFR 54.4(a)(3) as shown on LR-39218 and LR-39219, location D-7.

RAI 2.3-01 (2.3.4.6 sixth bullet)
RAI 2.3-01 (2.3.4.6 sixth bullet) indicated that drawing LR-39218, locations E-6 and E-7, pipe sections 3-MS-30, and upstream pipe sections after the valves TD-6-11, TD-6-12 1" "Drains to Trap" showed continuations to drawing LR-39233 and drawing LR-39219, locations E-6 and E-7, pipe sections 3-2MS-30, and upstream pipe sections after the valves 2TD-6-11, 2TD-6-12 showed continuations to drawing LR-39234. The NSPM response in a letter dated 12/18/08 stated that the continuation of drawings LR-39218 and LR-39219, locations E-6 and E-7, Drains to Trap, is shown on drawings LR-39233, location C-3, at valves TD-11-16, TD-6-11 and TD-6-12 and LR-39234, location C-3, at valves 2TD-11-16, 2TD-6-11 and 2TD-6-12. The continuations were located; however the scoping criteria of piping section (out of system dashed lines) before the valves TD-11-16 and 2TD-11-16 should be 10 CFR 54.4 (a)(1) instead of 10 CFR 54.4 (a)(2).

Response to RAI 2.3-01 (2.3.4.6 sixth bullet) Follow Up Question: On drawings LR-39233 and LR-39234, location C-3, the scoping classification for out of system dashed lines showing the 3" line, reducer and motor valves before valve TD-11-16 and 2TD-11-16, respectively, are incorrect; the lines, reducer and motor valves should be shown as within the scope of License Renewal per 10 CFR 54.4(a)(3) as shown on LR-39218 and LR-39219, location E-6.

RAI 2.3-01 (2.3.4.6 eighth bullet)
RAI 2.3-01 (2.3.4.6 eighth bullet) indicated that drawing LR-39218, locations E-8 and H-8, pipe sections 1/2-MS-59 and 12-MS-35, respectively, showed continuations to drawing LR-39233, and LR-39219, locations E-8 and H-8, pipe sections 1/2-2MS-32 and 12-2MS-35, respectively, showed continuations to drawing LR-39234. The NSPM response in a letter dated 12/18/08 stated, in part, that the continuation of drawings LR-39218 and LR-39219, location E-8, 1/2-MS-59 and 1/2-2MS-32, Drain to Trap, are shown on LR-39233 and LR-39234, location C-9, at valve TD-16-1 and 2TD-16-1, respectively. The scoping criteria of the dashed line before valve TD-16-1 on the continuation drawing LR-39233 at location C-9 differs from that on drawing LR-39218.

Response to RAI 2.3-01 (2.3.4.6 eighth bullet) Follow up Question: On drawings LR-39233 and LR-39234, location C-9, the scoping classification for valve TD-16-1 and 2TD-16-1, respectively, and out of system dashed lines showing the upstream ¾" and ½" piping are incorrect; the valves and lines should be shown as within the scope of License Renewal per 10 CFR 54.4(a)(3) as shown on drawing LR-39218, location E-8 (typical). On drawing LR-39219, location E-8, the scoping classification for line 1/2-2MS-32 and the valve shown at the MS/TB system boundary break are incorrect; the line and valve should be shown as within the scope of License Renewal per 10 CFR 54.4(a)(3) similar to the way this same configuration is shown on the Unit 1 drawing LR-39218, location E-8.

RAI 2.3-01 (2.3.4.6 thirteenth bullet)
RAI 2.3-01 (2.3.4.6 thirteenth bullet) indicated that drawings LR-39218 and LR-39219, location F-6, show a continuation of pipe sections 1-1/2-MS-40, 1-1/2-MS-41 and 2-2MS-40, 2-2MS-41 from stop valves of drawings LR-39233 and LR-39234, respectively. The NSPM response in a letter dated 12/18/08 stated that the continuations of drawing LR-39218, location F-6, Drains From Stop Valves, are shown on drawing LR-39233, location A-4, Turb Stop Valve Drains and on drawing LR-XH-2-15, location A-5, Connection 24. The continuations of LR-39219, location F-6, Drains From Stop Valves, are actually connected on drawing LR-39234, location A-4, similar to the Unit 1 drawing; the connections are not explicitly shown. The continuation is also shown on drawing LR-XH-1002-43, locations B-5 and B-6, Connection 24. The continuations were located; however, the scoping criteria of the continuations (as well as the stop valves) on LR-39233 differ. These lines are in scope for 10 CFR 54.4(a)(1). Confirm the scoping classification of these lines on drawing LR-39233.

Response to RAI 2.3-01 (2.3.4.6 thirteenth bullet) Follow up Question: On drawings LR-39233 and LR-39234, location A-4, the scoping classification for the turbine stop valves, and on drawing LR-39233, location A-4, the stop valve 1 ½" drains, are incorrect; the valves and drains should be shown as within the scope of License Renewal per 10 CFR 54.4(a)(3) as shown on drawings LR-39218 and LR-39219, location F-6.

RAI 3.1.2-02 Follow Up Question

In the 2/10/09 telephone conference, the NRC questioned the ability to reliably detect stress corrosion cracking of Class 1 cast austenitic stainless steel (CASS) piping utilizing an ultrasonic (UT) examination method as discussed in the NSPM Response to RAI 3.1.2-02. The NRC noted that current UT methods have not been qualified to detect cracks in a large-grained CASS microstructure. The NRC requested that NSPM consider the use of an enhanced visual examination for the detection of stress corrosion cracking (SCC) in CASS piping. NSPM agreed to provide a clarification to the original RAI response.

NSPM Response to RAI 3.1.2-02 Follow Up Question

In Part 4 of the NSPM Response to RAI 3.1.2-02 (letter dated 1/20/09), NSPM described the difficulties associated with the ultrasonic examination of cast austenitic stainless steel main coolant pipe welds. The response also included details of examination acceptance criteria used by PINGP to improve the UT inspection of the CASS reactor coolant piping. Although inspection procedures provide a “best effort” examination, NSPM acknowledges that the inspection procedures have not been demonstrated through a program consistent with ASME Section XI, Appendix VIII. In response to the 2/10/09 telephone conference with the NRC, NSPM provides the following clarification, which augments the Response to RAI 3.1.2-02 provided in the NSPM letter dated January 20, 2009.

NSPM acknowledges that current UT examination methods are not adequate for reliable detection of cracks in CASS components. NSPM intends to follow and support the industry initiatives focused on the development of an ultrasonic examination technique that can be demonstrated through a program consistent with ASME Section XI, Appendix VIII.

As shown in LRA Table 3.1.2-2, PINGP credits the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program (IWB, IWC, and IWD Program) to manage cracking due to SCC of the Class 1 CASS piping. The IWB, IWC, and IWD Program is implemented in accordance with the requirements of 10 CFR 50.55a, with specified limitations, modifications and NRC-approved alternatives, and applicable provisions of ASME Section XI. During the period of extended operation, should the PINGP IWB, IWC, and IWD Program, with NRC-approved alternatives, require volumetric examinations to be performed per ASME Section XI, Table IWB-2500-1, Examination Category B-J, on the Class 1 cast austenitic stainless steel main coolant pipe welds, then an ultrasonic examination method qualified under ASME Section XI, Appendix VIII will be utilized or an NRC-approved alternative (e.g., enhanced visual examination) will be implemented.

Section 3.1.2.2.13 Follow Up Question

LRA Further Evaluation Section 3.1.2.2.13 says it addresses nickel alloy in reactor internals, but the section is intended to address all nickel alloy in the RCS. Internals are addressed in SRP Sections 3.1.2.2.15 and 17. Correction or clarification is needed.

NSPM Response to Section 3.1.2.2.13 Follow Up Question

The further evaluation of cracking due to primary water stress corrosion cracking (PWSCC) contained in LRA Section 3.1.2.2.13 incorrectly refers to this aging effect/mechanism occurring in reactor vessel internals components. The associated Table 1 Item Number 3.1.1-31 is used in LRA Table 3.1.2-1, Pressurizer System – Summary of Aging Management Evaluation, and Table 3.1.2-4, Reactor Vessel System – Summary of Aging Management Evaluation. Therefore this further evaluation should refer to this aging effect/mechanism occurring in pressurizer and reactor vessel components. The first sentence of LRA Section 3.1.2.2.13 is hereby deleted and replaced with the following:

Cracking due to primary water stress corrosion cracking could occur for nickel alloy pressurizer and reactor vessel components.

Cracking due to primary water stress corrosion cracking for nickel alloy reactor internals components is evaluated under Table 1 Item Number 3.1.1-37 and in LRA Section 3.1.2.2.17.

RAI 3.3.2.2.4.1-01 Follow Up Question

The NSPM response to RAI 3.3.2.2.4.1-01 in a letter dated 1/20/2009 indicates that aging of the regenerative and non-regenerative heat exchangers is managed by the Water Chemistry and One-Time Inspection Programs. NRC indicated that use of Water Chemistry and One-Time Inspection for management of SCC is acceptable. However, the aging effect/mechanism of cracking due to cyclic loading in GALL would not be managed by these programs. The RAI dispositions cyclic loading by reference to a TLAA, but there is not a full analysis of fatigue in heat exchanger tubes, so the aging effect is not really being managed as a TLAA. One-time inspection of other components of the same materials and environment would not be representative of the unique cyclic loading experienced in the heat exchanger. NSPM indicated in the 2/10/09 telephone conference that cyclic loading is not an applicable aging mechanism for these heat exchangers and agreed to provide a discussion that shows why cyclic loading is not applicable.

NSPM Response to RAI 3.3.2.2.4.1-01 Follow Up Question

Part 1 of the NSPM Response to RAI 3.3.2.2.4.1-01 (1/20/09 letter) is hereby revised in its entirety. Note that Parts 2 - 6 of the original RAI response are unaffected, and remain as originally submitted. The revised Part 1 is as follows:

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. The combination of the Water Chemistry Program and the One-Time Inspection Program provides reasonable assurance that cracking due to SCC will be adequately managed for the Regenerative Heat Exchangers and non-regenerative heat exchangers (Letdown Heat Exchangers and Excess Letdown Heat Exchangers).

Cracking due to cyclic loading is not an applicable aging mechanism given the design and operation of the regenerative and non-regenerative heat exchangers at PINGP. Although a full fatigue analysis was not required for these heat exchangers, the Westinghouse design specification for these components included requirements to demonstrate that the heat exchangers satisfied all conditions of ASME Section III, Paragraph N-415.1, “Vessels Not Requiring Analysis for Cyclic Operation,” for the transient conditions specified. Through compliance with N-415.1 (a) through (f), which considers pressure fluctuations, thermal cycling, and mechanical loading, the peak stress limit discussed in Paragraph N-414.5 is satisfied for these heat exchangers, and an analysis for cyclic operation is not required. Therefore, from a design standpoint the Regenerative Heat Exchangers, Letdown Heat Exchangers, and Excess Letdown Heat Exchangers are not subject to cracking due to cyclic loading.

Additionally, a review of operating history did not reveal any degradation of the heat exchanger components (refer to Part 4 of the original RAI response for further discussion). The Regenerative Heat Exchangers and Letdown Heat Exchangers typically remain in service throughout the entire operating cycle. The Excess Letdown Heat Exchanger is normally isolated during plant operation and is put in service when the normal letdown path is not available. As a result, the heat exchangers are not subject to repeated thermal and pressure cycling. The heat exchangers have not experienced problems due to vibration. Generally, failure due to vibration is expected to be detected early in component service life, and is not considered an aging effect for the period of extended operation. Therefore, from an operational standpoint, cracking due to cyclic loading does not apply to these heat exchangers.

As illustrated above, the design and operation of the Regenerative Heat Exchangers, Letdown Heat Exchangers, and Excess Letdown Heat Exchangers preclude cyclic loading from being an aging mechanism requiring aging management during the period of extended operation. The following LRA changes are hereby made in order to reflect that cracking due to cyclic loading is not applicable to the regenerative and non-regenerative heat exchangers at PINGP.

In LRA Table 3.3.1 (Page 3.3-45), Summary of Aging Management Evaluations in Chapter VII of NUREG-1801 for Auxiliary Systems, Item Number 3.3.1-07 is hereby replaced in its entirety as shown below:

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-07	Stainless steel non-regenerative heat exchanger components exposed to treated borated water >60°C (>140°F)	Cracking due to stress corrosion cracking and cyclic loading	Water Chemistry and a plant-specific verification program. An acceptable verification program is to include temperature and radioactivity monitoring of the shell side water, and eddy current testing of tubes.	Yes, plant specific	The plant-specific AMP that manages cracking due to stress corrosion cracking of stainless steel non-regenerative heat exchanger components exposed to treated borated water >60°C (>140°F) in addition to the Water Chemistry Program is the One-Time Inspection Program. Cracking due to cyclic loading is not an applicable aging mechanism. Further evaluation is documented in Section 3.3.2.2.4.1.

In LRA Table 3.3.1 (Page 3.3-45), Summary of Aging Management Evaluations in Chapter VII of NUREG-1801 for Auxiliary Systems, Item Number 3.3.1-08 is hereby replaced in its entirety as shown below:

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-08	Stainless steel regenerative heat exchanger components exposed to treated borated water >60°C (>140°F)	Cracking due to stress corrosion cracking and cyclic loading	Water Chemistry and a plant-specific verification program. The AMP is to be augmented by verifying the absence of cracking due to stress corrosion cracking and cyclic loading. A	Yes, plant specific	The plant-specific AMP that manages cracking due to stress corrosion cracking of stainless steel regenerative heat exchanger components exposed to treated borated water >60°C (>140°F) in addition to the Water Chemistry Program is the One-Time Inspection Program. Cracking due to cyclic loading is not an applicable

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
			plant specific aging management program is to be evaluated.		aging mechanism. Further evaluation is documented in Section 3.3.2.2.4.2.

In LRA Section 3.3.2.2.4 (Pages 3.3-34 and 3.3-35), under Cracking due to Stress Corrosion Cracking and Cyclic Loading, Items 1 and 2 are revised in their entirety to read as follows:

1. Cracking due to stress corrosion cracking could occur in stainless steel non-regenerative heat exchanger components exposed to treated water greater than 140°F. This aging effect is managed with a combination of the Water Chemistry Program and the One-Time Inspection Program. Cracking due to cyclic loading is not an applicable aging mechanism since the non-regenerative heat exchanger components were designed to adequately cope with the stresses induced by cyclic loading, which precluded the need for a detailed analysis for cyclic operation.

   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 One-Time Inspection Program performs sampling inspections using nondestructive examination techniques that either verify unacceptable degradation is not occurring or trigger additional actions. These programs assure the intended function of affected components will be maintained during the period of extended operation. The One-Time Inspection Program is selected in lieu of temperature and radioactivity monitoring of the shell side water and eddy current testing of tubes.

   This position was found acceptable to the NRC staff in NUREG-1785, Safety Evaluation Report Related to the License Renewal of H. B. Robinson Steam Electric Plant, Unit 2. Section 3.3.2.2.8 of the applicant's Safety Evaluation Report states:

   > "In LRA Table 3.3-1, row 8 the applicant stated that stress corrosion cracking (SCC) is an applicable aging mechanism for the seal water, excess letdown, and regenerative heat exchangers.
   >
   > The applicant credited the Water Chemistry Program for managing the crack initiation and growth due to SCC in these heat exchangers and the

Closed-Cycle Cooling Water System Program for managing the aging effect for heat exchangers cooled by the CCW system. To verify the effectiveness of the Water Chemistry Program in preventing cracking due to SCC, the applicant credited an inspection of small-bore Class 1 piping system and components connected to the RCS under the One-Time Inspection Program in selected locations where degradation would be expected. The applicant stated that management of SCC for this group is consistent with the GALL Report with the exception that the onetime inspection will be used instead of the eddy current testing recommended in the GALL Report. The Water Chemistry Program and the One-Time Inspection Program are evaluated in Sections 3.0.3.3 and 3.0.3.9 of this SER. The staff finds that these programs can effectively manage the cracking initiation and growth due to SCC for the above components that are applicable to RNP auxiliary systems.

On the basis of its review, the staff finds that the applicant has adequately evaluated the management of crack initiation and growth due to SCC and cyclic loading for components in the auxiliary systems, as recommended in the GALL Report. On the basis of this finding, and the finding that the remainder of the applicant's program is consistent with GALL, the staff concludes that the applicant has demonstrated that these aging effects will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation."

2. Cracking due to stress corrosion cracking could occur in stainless steel regenerative heat exchanger components exposed to treated water greater than 140°F. This aging effect is managed with a combination of the Water Chemistry Program and the One-Time Inspection Program. Cracking due to cyclic loading is not an applicable aging mechanism since the regenerative heat exchanger components were designed to adequately cope with the stresses induced by cyclic loading, which precluded the need for a detailed analysis for cyclic operation. See Section 3.3.2.2.4.1 for additional details.

Section 3.3.2.2.12.2 Follow Up Question

The applicant states in LRA Section 3.3.2.2.12.2 that MIC of stainless steel piping, piping components, and piping elements exposed to a lubricating oil environment is not managed based on operating experience. Operating experience alone is not justification for eliminating management of an aging mechanism. Provide plant-specific operating history that indicates MIC is not active. Provide additional information, including inspection results of weld heat affected zones, that demonstrates stainless steel piping, piping components and piping elements are not subject to MIC when exposed to lubricating oil.

NSPM Response to Section 3.3.2.2.12.2 Follow Up Question

Microbiologically Influenced Corrosion (MIC) is facilitated by stagnant conditions, fouling, internal crevices, contact with untreated water, and contact with contaminated soils. While MIC contamination is possible in lubricating oil applications, the likelihood of MIC causing extensive damage in lube oil systems is minimal. Even if contamination of the oil occurs, the relatively clean systems and addition of corrosion inhibitors to the lubrication oil does not provide an environment conducive to microorganism growth. The potential for MIC growth and subsequent corrosion effects in lube oil systems are very small based on the addition of lube oil corrosion additives, oil purity testing programs, and the low likelihood of lube oil contamination. Even if MIC were to be introduced into these systems, which would be event-driven as opposed to age related, sampling programs would detect and correct the situation prior to MIC causing any appreciable corrosion of lubricating oil system components. Review of industry failure data, generic communications, and plant-specific operating experience confirm that MIC is not expected to occur in lubricating oil systems unless external contamination of the lubricating oil has occurred (event driven). Therefore, MIC is not considered to be an applicable aging mechanism in lubricating oil systems.

The following changes are hereby made to the LRA.

In LRA section 3.3.2.2.9.2 on Page 3.3-39, the second sentence is deleted and replaced with the following:

> PINGP excludes loss of material due to fouling or microbiologically influenced corrosion in a lubricating oil environment based upon an evaluation of the materials of construction and operating environment, along with industry and plant specific operating experience.

In LRA section 3.3.2.2.12.2 on Page 3.3-42, the second sentence is deleted and replaced with the following:

> PINGP excludes loss of material due to microbiologically influenced corrosion in a lubricating oil environment based upon an evaluation of the materials of construction and operating environment, along with industry and plant specific operating experience.

In LRA section 3.4.2.2.5.2 on Page 3.4-17, the following new sentence is inserted immediately after the existing first sentence:

> PINGP excludes loss of material due to microbiologically influenced corrosion in a lubricating oil environment based upon an evaluation of the materials of construction and operating environment, along with industry and plant specific operating experience.

In LRA Section 3.4.2.2.8 on Page 3.4-20, the following new sentence is inserted immediately after the existing first sentence:

> PINGP excludes loss of material due to microbiologically influenced corrosion in a lubricating oil environment based upon an evaluation of the materials of construction and operating environment, along with industry and plant specific operating experience.

Table 3.4.2-4 Follow Up Question

NRC requested clarification on a line item in LRA Table 3.4.2-4 on page 3.4-75 for Flex Connections of Stainless Steel in an Outdoor Air - Sheltered environment. The line item has Note G (environment not in GALL) but points to a GALL Table 1 line for Indoor Air - Uncontrolled. Reviewer asked what the external environment actually is.

NSPM Response to Table 3.4.2-4 Follow Up Question

LRA Table 3.4.2-4 (page 3.4-75) shows stainless steel flex connections exposed to an environment of outdoor air – sheltered (ext). These components are outdoors and are insulated and jacketed (i.e., sheltered). The insulation and jacket protect (shelter) the components from precipitation. The humidity experienced in an outdoor air – sheltered environment would be equivalent to that in an indoor air – uncontrolled environment. Therefore, the environment is equivalent to plant indoor air – uncontrolled and has been evaluated using GALL Volume 2 line item VIII.I-10 (GALL Volume 1 line item 3.4.1-41) with Note G which states, "Environment is not in NUREG-1801 for this component and material." Alternatively, Note A coupled with Note 419 could have been used. Note 419 states, "The environment for this line item is equivalent to Plant Indoor Air – Uncontrolled with the potential for moisture or condensation." For example, see LRA Table 3.4.2-4 (page 3.4-87), stainless steel valves exposed to an environment of outdoor air – sheltered (ext). Both Note G and Note A coupled with Note 419 are correct.

B2.1.9 Follow Up Question

The new Closed-Cycle Cooling Water System Program exception identified in the letter dated 2/6/09 indicated that no performance testing is conducted on three chiller loops, and that aging management is being performed with water chemistry control under the CCCW System Program. This is not sufficient to tell whether aging is occurring. NSPM agreed to modify the exception to clarify that visual inspections will be performed on the three chiller loops affected by the exception.

NSPM Response to B2.1.9 Follow Up Question

In LRA Section B2.1.9, under Exceptions to NUREG-1801 (Pages B-27 and B-28), a third bullet is hereby added to read as follows. Note that the following text replaces, in its entirety, the text of the exception previously provided in the February 6, 2009 letter.

- Detection of Aging Effects

  No periodic performance testing is conducted on the Cold Lab Chiller Loop, Computer Room Chiller Loop, or Hot Lab Chiller Loop as recommended by NUREG-1801. Periodic visual inspections will be performed on these systems to identify the presence of aging effects and to confirm the effectiveness of chemistry controls. The coolant environment in these chiller loops is managed by periodic sampling and chemistry control. Chemical controls and visual inspections are adequate to manage aging effects in these closed-cycle cooling water systems.

B2.1.19 Follow Up Question

In the telephone conference of 2/10/09, the NRC noted that PINGP has taken an exception to the GALL recommendation for monitoring of fuel oil for biological activity. In lieu of specific biological testing, the NRC requested clarification as to the type of testing that is performed that would detect the presence of biological activity in fuel oil. Additionally, the NRC requested clarification on the use of ASTM Standard D 975 in the PINGP Fuel Oil Chemistry Program.

NSPM Response to B2.1.19 Follow Up Question

As stated in the NSPM Response to RAI B2.1.19-2 (12/18/08 letter), PINGP does not monitor fuel oil for biological activity. Fuel oil samples have not shown cloudiness, sludge, or other conditions that would indicate significant biological activity or fuel degradation. The PINGP Fuel Oil Chemistry Program performs water and sediment testing in accordance with ASTM Standard D 1796. Particulate contamination testing is performed in accordance with ASTM Standard D 6217. Use of these standards is consistent with those recommended in NUREG-1801, Program XI.M30, Elements 1 and 6. ASTM D 1796 uses a centrifuge test method to measure the volume of water and sediment in fuel oil. ASTM D 6217 assesses the mass quantity of particulate contamination present in fuel oil by filtration using a conservative filter pore size of 0.8 μm. Since biological activity would produce sludge and other by-products of metabolism, the test results for water and sediment (reported in volume percent) and particulate contamination (reported in mass per volume of fuel filtered) would identify the presence of biological activity in the fuel oil. Test results would exhibit an increase if biological activity were present. The program acceptance criterion for water and sediment content is 0.05 % (max.) and the acceptance criterion for particulate contamination is 20 mg/L (max.).

NUREG-1801, Program XI.M30, Fuel Oil Chemistry, Element 1 states, “The program is focused on managing the conditions that cause general, pitting, and microbiologically-influenced corrosion (MIC) of the diesel fuel tank internal surfaces in accordance with the plant’s technical specifications…” As required by PINGP Technical Specifications, Section 5.5.11, “The program shall include sampling and testing requirements, and acceptance criteria, all in accordance with the limits specified in Table 1 of ASTM D 975-77 when checked for viscosity, water, and sediment.” Therefore, consistent with NUREG-1801 and plant Technical Specifications, the PINGP Fuel Oil Chemistry Program utilizes the requirements of ASTM Standard D 975-77 to prescribe the required properties of fuel oil in use at PINGP.