AMP Audit

Total Items: 160

Monticello Nuclear Generating Plant License Renewal RAIs and Audit Questions

Monticello Nuclear Generating Plant License Renewal Audit Questions

Sorted by Status, NRC Reviewer/Auditor, and RAI/Question Number

Audit Question No.: B2.1.10-01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question:

PBD/AMP-038 says that, "At MNGP, all IGSCC susceptible materials have been replaced or protected with a cladding of resistant weld material. Therefore, all piping welds are now classified as IGSCC Category A in accordance with NUREG-0313 and GL 88-01." In Section 3.10.B the PBD also says, "All piping welds are now classified as IGSCC Category A in accordance with NUREG-0313 and GL 88-01 and are being examined in accordance with the Risk Informed Inservice Inspection Program."

MNGP DBD-T12 (Design Basis Document: Plant Piping), Revision D, Section 2.3.23.B.2) identifies one of the corrective actions proposed in response to GL 88-01 as, "Inspect welds not meeting Category A requirements of NUREG-0313, Rev. 2, at each refueling outage and replace if crack indications are found or replace as a preventative measure during a future outage."

QUESTION:
Since all IGSCC susceptible material has been replaced or protected with a cladding of resistant weld material, on what frequency are these welds now inspected? What is the technical and/or regulatory basis for that inspection frequency?

Date Received: 6/16/2005 Potential Submittal on ☑ Potential LRA Update Required ☑ Assoc LRA Section - Appendix B

Draft Response:

The BWR Stress Corrosion Cracking AMP is applicable to all BWR piping made of austenitic stainless steel that is 4 inches or larger in nominal diameter and contains reactor coolant at a temperature above 93°C (200°F) during power operation, regardless of code classification. GL 88-01 requires an augmented ASME Section XI ISI Program to inspect welds that are not classified as Category A. All piping welds at Monticello are now classified as IGSCC Category A in accordance with NUREG-0313 and GL 88-01 and the augmented ASME Section XI ISI inspection frequency of GL 88-01 no longer applies for any welds. Therefore, all piping welds are scheduled and being examined in accordance with the Risk Informed Inservice Inspection Program.

JPP 6/20/05

Final Response:

See response to RAI# B2.1.26-01.

The BWR Stress Corrosion Cracking AMP is applicable to all BWR piping made of austenitic stainless steel that is 4 inches or larger in nominal diameter and contains reactor coolant at a temperature above 93°C (200°F) during power operation, regardless of code classification. GL 88-01 requires an augmented ASME Section XI ISI Program to inspect welds that are not classified as Category A. All piping welds at Monticello are now classified as IGSCC Category A in accordance with NUREG-0313 and GL 88-01 and the augmented ASME Section XI ISI inspection frequency of GL 88-01 no longer applies for any welds. Therefore, all piping welds are scheduled and being examined in accordance with the Risk Informed Inservice Inspection Program.

JPP 6/20/05

Audit Question No.: B2.1.11-01

Source: **AMP Audit** **Status:** **Sufficient per NRC** **Author:** **Jackson** **MNGP Owner:** **Bill O'Brien** **Discipline:** **Mechanical**

Question: Acronym question: What does what does the "/D" mean in IG/DSCC in the Operating Experience section of MNGP LRA evaluation of B2.1.11 (BWR Vessel ID Attachment Welds)?

Date Received: 6/7/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: SIL No. 624, "Stress Corrosion Cracking in Alloy 182 Welds in Shroud Support Structure", discusses the susceptibility of Alloy 182 weld material to "interdendritic stress corrosion cracking" (IDSCC).

JPP 6/9/05

Final Response: SIL No. 624, "Stress Corrosion Cracking in Alloy 182 Welds in Shroud Support Structure", discusses the susceptibility of Alloy 182 weld material to "interdendritic stress corrosion cracking" (IDSCC).

Audit Question No.: B2.1.12-01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question: The MNGP LRA evaluation of AMP B2.1.12 (BWR Vessel Internals) notes that the existing program will be enhanced by addition of several BWRVIP repair/replacement guidelines to the existing program.

QUESTION: What is the reason that these guidelines have not previously been in the program? Simply that there has been no Monticello failure experience where the guidance would be needed? Or, has some alternative been used for situations where there guidelines would be applicable? If some alternative has been used, are there any important differences between what was done and what is recommended in the BWRVIP guidelines?

Date Received: 6/7/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The reason that the guidelines have not yet been added to the program is due to them not yet being approved by the NRC. Just recently in January 19, 2005 a number of the repair documents were transmitted to the Report Revision Focus Group under BWRVIP 2005-015. These include the NRC SER and will be incorporated in the Monticello BWRVIP Program on an as needed basis once officially issued. There has been no need to use the repair methods in these documents at Monticello. All indications detected have been able to be evaluated using the Inspection and Evaluation (I&E) guidelines for the specific components. There have been no alternative methods used in performing repairs after the creation of the BWRVIP. For example repairs on the Core Spray T-boxes have been completed, but these were completed prior to any BWRVIP document being developed.

JPP 6/10/05

Final Response: The reason that the guidelines have not yet been added to the program is due to them not yet being approved by the NRC. Just recently in January 19, 2005 a number of the repair documents were transmitted to the Report Revision Focus Group under BWRVIP 2005-015. These include the NRC SER and will be incorporated in the Monticello BWRVIP Program on an as needed basis once officially issued. There has been no need to use the repair methods in these documents at Monticello. All indications detected have been able to be evaluated using the Inspection and Evaluation (I&E) guidelines for the specific components. There have been no alternative methods used in performing repairs after the creation of the BWRVIP. For example repairs on the Core Spray T-boxes have been completed, but these were completed prior to any BWRVIP document being developed.

Audit Question No.: B2.1.12-02

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question: The MNGP LRA evaluation of AMP B2.1.12 (BWR Vessel Internals) states under "Parameters Monitored or Inspected" that no relief has been requested for vessel internal components with hydrogen water chemistry per the guidelines of BWRVIP-62.

QUESTION: What are future expectations of requesting relief based on implementation of HWC at MNGP? Is the plant in a wait-and-see mode in regard to this?

Date Received: 6/7/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Monticello is awaiting the finalization of BWRVIP-62 and NRC approval prior to consideration of the reduced examinations on vessel internals that would be a benefit of HWC.

JPP 6/10/05

Final Response: Monticello is awaiting the finalization of BWRVIP-62 and NRC approval prior to consideration of the reduced examinations on vessel internals that would be a benefit of HWC.

Audit Question No.: B2.1.12-03

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question:

With reference to MNGP AMP B2.1.12 (BWR Vessel Internals): The MNGP LRA says that, "The in-vessel examination procedures implement the recommendations of the BWRVIP guidelines, as well as the requirements of Section XI of the ASME Boiler and Pressure Vessel Code." It further says, "The inspections are performed consistent with the recommendations of the BWRVIP guidelines, as described in MNGP procedures, as well as the requirements of the ASME Code." Also, "Evaluation and disposition of indications are conducted consistent with the BWRVIP guidelines or ASME Code, as appropriate."

QUESTION: Do the MNGP implementing procedures and/or instructions for the MNGP BWR Vessel Internals Program (when enhanced) include all of the BWRVIP guidelines applicable to Monticello and listed in NUREG-1801, Section XI.M9 (BWR Vessel Internals) without deviation or exception? If Monticello implementing procedures or instructions deviate from or take exception to any of the applicable BWRVIP guidelines, please describe and provide the basis for those deviations or exceptions.

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response:

BWRVIP	Disposition
2	Enhancement to repair/replacement guidelines
3	MNGP Procedure: PEI-02.05.05 (Section 1.0)
7	MNGP Procedure: EWI-8.1.1 (5.12.1), EWI-8.1.2, (3.10.1)
14	Enhancement to repair/replacement guidelines
16	Enhancement to repair/replacement guidelines
18	MNGP Procedure: EWI- 8.1.1 (5.3), EWI 8.1.2 (3.1)
19	Enhancement to repair/replacement guidelines
25	MNGP Procedure: EWI- 8.1.1 (5.4), EWI 8.1.2 (3.2)
26	MNGP Procedure: EWI- 8.1.1 (5.5), EWI 8.1.2 (3.3)
38	MNGP Procedure: EWI- 8.1.1 (5.7), EWI 8.1.2 (3.5)
41	MNGP Procedure: EWI- 8.1.1 (5.8), EWI 8.1.2 (3.6)
42	N/A to MNGP (No LPCI Coupling)
44	Enhancement to repair/replacement guidelines
45	Enhancement to repair/replacement guidelines
47	MNGP Procedure: EWI- 8.1.1 (5.9), EWI 8.1.2 (3.7)
50	Enhancement to repair/replacement guidelines
51	Enhancement to repair/replacement guidelines
52	Enhancement to repair/replacement guidelines
56	N/A to MNGP (No LPCI Coupling)
57	Enhancement to repair/replacement guidelines
58	Enhancement to repair/replacement guidelines
59	Enhancement to repair/replacement guidelines
60	Enhancement to repair/replacement guidelines
62	No relief has been requested for vessel internal components with hydrogen water chemistry per the guidelines of BWRVIP-62.
63	MNGP Procedure: EWI-8.1.1 (5.12.1), EWI-8.1.2, (3.10.1)
76	MNGP Procedure: EWI-8.1.1 (5.12, 7.7), EWI 8.1.2 (3.10)

Two exceptions are taken to the following BWRVIP guidelines:
BWRVIP 18, See MNGP Procedure EWI- 8.1.1, Section 5.3.1.A for the basis of the exception.
BWRVIP 25, See MNGP Procedure EWI- 8.1.1, Section 8.2 for the basis of the exception.

JPP 6/13/05

Final Response: The Program includes the following BWRVIPs - 2, 3, 7, 14, 16, 18, 19, 25, 26, 38, 41, 42, 44, 45, 47, 50, 51, 52, 56, 57, 58, 59, 60, 62, 63, 76.
Two exceptions are taken to the following BWRVIP guidelines:
BWRVIP 18 and BWRVIP 25.

Audit Question No.: B2.1.12-04

Source: AMP Audit **Status: Sufficient per NRC** **Author: Jackson** **MNGP Owner: Bill O'Brien** **Discipline: Mechanical**

Question: B2.1.12 - MNGP EWI-08.01.01 (Boiling Water Reactor Vessel Internals Project Administrative Manual), Revision 4, provides the program requirements for implementation of the BWRVIP Documents at Monticello. Section 8 of the EWI identifies the considerations and documentation developed and residing in the vessel and internals program if deviations are taken from any of the techniques present in the BWRVIP guidelines. Section 8 of EWI-08.01.01 requires a technical justification to be developed if deviations from the BWRVIP techniques are required. There are two descriptions of two deviations, with associated technical justifications, in Revision 4 of the EWI.

QUESTIONS:
Are the two deviations documented in Section 8, Revision 4 of the EWI the only deviations that MNGP has taken from the guidelines and techniques in all BWRVIP Documents applicable to Monticello?

Please provide a brief discussion of MNGP's level of commitment to the guidelines and techniques in the BWRVIP Documents applicable to Monticello, including confirmation that this level of commitment will be continued throughout the extended period of operation.

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The two deviations, documented in MNGP procedures for BWRVIPs, are the only deviations that MNGP has taken from the guidelines in all BWRVIP Documents applicable to Monticello.

In a letter dated May 30,1997 from Carl Terry (Niagara Mohawk Power Company, Chairman of BWR Vessel and Internals Project) to Brian Sheron (NRC), the BWRVIP member utilities commitments were expressed. The letter stated "we will implement the BWRVIP products at each of our plants as appropriate considering individual plant schedules, configurations and needs". One such document is BWRVIP-94, Program Implementation Guide. BWRVIP-94 states that each member utility, of which Monticello/NMC is, will implement the BWRVIP guidelines to the fullest extent possible.

Final Response: The two deviations, documented in MNGP procedures for BWRVIPs, are the only deviations that MNGP has taken from the guidelines in all BWRVIP Documents applicable to Monticello.

In a letter dated May 30,1997 from Carl Terry (Niagara Mohawk Power Company, Chairman of BWR Vessel and Internals Project) to Brian Sheron (NRC), the BWRVIP member utilities commitments were expressed. The letter stated "we will implement the BWRVIP products at each of our plants as appropriate considering individual plant schedules, configurations and needs". One such document is BWRVIP-94, Program Implementation Guide. BWRVIP-94 states that each member utility, of which Monticello/NMC is, will implement the BWRVIP guidelines to the fullest extent possible.

Audit Question No.: B2.1.12-05

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question:

B2.1.12 - BWRVIP-41 (BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines), Table 3.3-1, Matrix of Inspection Options, Location 3/TS-2 concerns the inspection of jet pump thermal sleeve to safe end welds. The associated note says that , "this weld may not be accessible for visual inspection. BWRVIP Inspection Committee is currently addressing the need for developing an inspection technique for this weld. Inspection is recommended when the technique becomes available."

The BWRVIP program for Applicant Action Items indicates that each plant should perform a site specific aging management review for the thermal sleeve welds. In Table 3.1.2-3, the MNGP LRA provides the AMR for the thermal sleeves. The BWR Vessel Internals is the identified aging management program. The BWR Vessels Internals program states that inspections will be conducted in accordance with BWRVIP-41.

QUESTION:
How will the thermal sleeve welds be managed/inspected during the period of extended operation?

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response:

Per MNGP Procedure for BWRVIPs, "There is currently no inspection technique developed for examining the nozzle thermal sleeves welds (TS-2). The MNGP will continue to monitor the progress of the BWRVIP Committee in the development of the examination technique. It is important to note that this particular region is protected by Hydrogen Water Chemistry and therefore, considered to be protected against intergranular stress corrosion cracking."

MNGP LRA, Page 3-64, Table 3.1.2-3, Reactor Coolant System - Reactor Pressure Vessel Internals, Jet Pump Assemblies - The thermal sleeves are managed for crack initiation and growth due to stress corrosion cracking, intergranular stress corrosion cracking, and irradiation-assisted stress corrosion cracking and credits the BWR Vessel Internals and Plant Chemistry Programs for aging management.

Final Response:

Per MNGP Procedure for BWRVIPs, "There is currently no inspection technique developed for examining the nozzle thermal sleeves welds (TS-2). The MNGP will continue to monitor the progress of the BWRVIP Committee in the development of the examination technique. It is important to note that this particular region is protected by Hydrogen Water Chemistry and therefore, considered to be protected against intergranular stress corrosion cracking."

MNGP LRA, Page 3-64, Table 3.1.2-3, Reactor Coolant System - Reactor Pressure Vessel Internals, Jet Pump Assemblies - The thermal sleeves are managed for crack initiation and growth due to stress corrosion cracking, intergranular stress corrosion cracking, and irradiation-assisted stress corrosion cracking and credits the BWR Vessel Internals and Plant Chemistry Programs for aging management.

Audit Question No.: B2.1.12-07

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Bill O'Brien **Discipline:** Programs

Question:

B2.1.12 - In MNGP's response to previous trip Audit Question B2.1.12-03, MNGP provided a list of BWRVIP documents implemented by the applicant. The list did not include BWRVIP-75 (BWR Vessel and Internals Project Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules), which provides the technical basis for revision of the Generic Letter GL 88-01 inspection schedules.

QUESTION:
Is BWRVIP-75 included in the MNGP program? If not, why not?

Date Received: 7/20/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - B2.1.12

Draft Response:

BWRVIP-75, "Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules (NUREG-0313)" is not discussed in NUREG 1801, XI.M09 (B2.1.12). BWRVIP-75 is discussed in XI.M7 BWR Stress Corrosion Cracking (B2.1.10).

MNGP has taken the option of not using BWRVIP-75 to modify the inspection scope in the GL 88-01 program. All IGSCC susceptible materials have been replaced or protected with a cladding of resistant weld material. Therefore, all piping welds are now classified as IGSCC Category A in accordance with NUREG-0313 and GL 88-01 and therefore, reliance on the technical basis of BWRVIP-75 is not needed.

Final Response:

BWRVIP-75, "Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules (NUREG-0313)" is not discussed in NUREG 1801, XI.M09 (B2.1.12). BWRVIP-75 is discussed in XI.M7 BWR Stress Corrosion Cracking (B2.1.10).

MNGP has taken the option of not using BWRVIP-75 to modify the inspection scope in the GL 88-01 program. All IGSCC susceptible materials have been replaced or protected with a cladding of resistant weld material. Therefore, all piping welds are now classified as IGSCC Category A in accordance with NUREG-0313 and GL 88-01 and therefore, reliance on the technical basis of BWRVIP-75 is not needed.

Audit Question No.: B2.1.2-01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question:

1. The Program Description for AMP XI.M1 in NUREG-1801, April 2001, states that "this program generally includes ...all Class 1, 2 and 3 pressure retaining components and their integral attachments." The MNGP LRA Program Description for MNGP AMP B2.1.2 (ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD) states that Class 1 and 2 piping is being inspected in accordance with the RI-ISI as described in EPRI TR-112657. It is not clear from the description in MNGP LRA whether certain categories or types of Class 1 and 2 piping components may have been excluded from the AMP as implemented at MNGP on the basis of RI-ISI. Please provide additional information in this regard:

Has RI-ISI been credited to exclude from inspections any categories or types of piping components that would otherwise be included in the inspections required by ASME Section XI 1995 Edition through the 1996 Addenda? If so, please identify the component categories or types and briefly discuss the justification for their exclusion.

Date Received: 6/7/2005 Potential Submittal on ☑ Potential LRA Update Required ☑ Assoc LRA Section - Appendix B

Draft Response: See response to RAI# B2.1.26-01.

MNGP's License Renewal ASME Section XI AMP, the RI-ISI is not credited for excluding from inspection any categories or types of piping components that would otherwise be included as required by ASME Section XI 1995 Edition through the 1996 Addenda.

Final Response: See response to RAI# B2.1.26-01.

MNGP's License Renewal ASME Section XI AMP, the RI-ISI is not credited for excluding from inspection any categories or types of piping components that would otherwise be included as required by ASME Section XI 1995 Edition through the 1996 Addenda.

Audit Question No.: B2.1.2-02

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question: In its statement of NUREG-1801 Consistency for AMP B2.1.2 (ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD), the MNGP LRA says "exceptions to ASME Code requirements that have been granted by approved Code Cases or relief requests, or modifications by 10 CFR 50.55a are not considered to be exceptions to NUREG-1801 criteria." Please provide a summary of any categories or types of Class 1, 2, or 3 pressure retaining components or their integral attachments that would be included in the inspections required by ASME Section XI 1995 Edition through the 1996 Addenda, but which have subsequently been excluded from inspection on the basis of approved Code Cases or relief requests, or modifications by 10 CFR 50.55a.

Date Received: 6/7/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Per the Dresden/Quad Cities SER, NUREG 1796- "The staff position is that current Relief Requests granted by the staff have no bearing on License Renewal commitments, because the basis for the relief request and the period of time during which the relief request is applicable generally will not carry over to the period of extended operation. Consequently, for license renewal the staff expects a commitment to IWE and supplemental requirements consistent with 10 CFR 50.55a."

MNGP's position is consistent with the above staff position. The MNGP License Renewal ASME Section XI, ISI AMP will be in accordance with 10 CFR 50.55a, which includes the process for determining which relief requests and supplemental requirements apply. Relief Requests are subject to periodic review by the NRC under 10CFR 50.55a. It cannot be predicted which existing or new relief requests may be part of the future MNGP License Renewal AMP. However, MNGP will only implement modifications to the program during the extended period of operation as allowed by 10CFR50.55a.

Therefore, under the MNGP's License Renewal ASME Section XI, ISI AMP, no Class 1, 2, or 3 pressure retaining components or their integral attachments have been excluded from inspection on the basis of approved Code Cases or relief requests, or modifications by 10 CFR 50.55a.

JPP 6/9/05

Final Response: Per the Dresden/Quad Cities SER, NUREG 1796- "The staff position is that current Relief Requests granted by the staff have no bearing on License Renewal commitments, because the basis for the relief request and the period of time during which the relief request is applicable generally will not carry over to the period of extended operation. Consequently, for license renewal the staff expects a commitment to IWE and supplemental requirements consistent with 10 CFR 50.55a."

MNGP's position is consistent with the above staff position. The MNGP License Renewal ASME Section XI, ISI AMP will be in accordance with 10 CFR 50.55a, which includes the process for determining which relief requests and supplemental requirements apply. Relief Requests are subject to periodic review by the NRC under 10CFR 50.55a. It cannot be predicted which existing or new relief requests may be part of the future MNGP License Renewal AMP. However, MNGP will only implement modifications to the program during the extended period of operation as allowed by 10CFR50.55a.

Therefore, under the MNGP's License Renewal ASME Section XI, ISI AMP, no Class 1, 2, or 3 pressure retaining components or their integral attachments have been excluded from inspection on the basis of approved Code Cases or relief requests, or modifications by 10 CFR 50.55a.

Audit Question No.: B2.1.2-03

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question:

In its statement of NUREG-1801 Consistency for AMP B2.1.2 (ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD), the MNGP LRA says "exceptions to ASME Code requirements that have been granted by approved Code Cases or relief requests, or modifications by 10 CFR 50.55a are not considered to be exceptions to NUREG-1801 criteria."

However, relief requests are granted for a single 10-year inspection interval, and there is no assurance that a current relief request would be approved or that the relief would be appropriate for the extended interval of operation. Therefore, the intention of the statement that "exceptions to ASME Code requirements that have been granted by ... relief requests ... are not considered to be exceptions to NUREG-1801 criteria" is not clear. Please provide additional discussion of how this logic was applied in evaluating NUREG-1801 consistency. What, if anything, would be different in MNGP's evaluation of NUREG-1801 consistency if this logic were not applied in the evaluation?

Date Received: 6/7/2005 Potential Submittal on ☑ Potential LRA Update Required ☑ Assoc LRA Section - Appendix B

Draft Response: See response to RAI# B2.1.26-01.

Final Response: See response to RAI# B2.1.26-01.

Audit Question No.: B2.1.2-04

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question: The LRA description of AMP B2.1.2 (ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD) identifies two exceptions to NUREG-1801. The LRA further states that one of these exceptions is "per 10 CFR 50.55a(b)(2)(xi)" and the other of these exceptions is "per 10 CFR 50.55a(b)(2)(xxi)(B)." However, earlier under NUREG-1801 Consistency the LRA states that "exceptions to ASME Code requirements that have been granted by ... modifications by 10 CFR 50.55a are not considered to be exceptions to NUREG-1801 criteria." It seems inconsistent to say in one place that modifications to the ASME Code requirements granted by 10 CFR 50.55a are not considered to be exceptions to NUREG-1801 and in a second place to identify requirements of 10 CFR 50.55a as exceptions to NUREG-1801. Please provide further discussion and clarification of the LRA wording with regard to these items.

Date Received: 6/7/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Per NUREG-1801, Chapter XI.M1, Program Description -"The Code of Federal Regulations, 10 CFR 50.55a, imposes the in-service inspection (ISI) requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI, for Class 1, 2, and 3 pressure-retaining components and their integral attachments in light-water cooled power plants. Inspection, repair, and replacement of these components are covered in Subsections IWB, IWC, and IWD, respectively, in the 1995 edition through the 1996 addenda."

The MNGP License Renewal ASME Section XI, ISI AMP is based on 10 CFR 50.55a and the 1995 edition through the 1996 addenda of ASME Section XI. However, within 10CFR 50.55a there are two codified exceptions that are utilized at MNGP, which allow a different ASME Section XI Edition or Addenda to be used. These were included as exceptions in the LRA since they do not meet the literal definition of this program as described in NUREG-1801, i.e., they are codified exceptions to "ASME Section XI, 1995 edition through 1996 addenda" and they are not subject to NRC review and approval in the same manner as plant specific relief requests in accordance with 10 CFR50.55a. As they are codified, it is possible they could extend into the license renewal period of operation.

JPP 6/10/05

Final Response: Per NUREG-1801, Chapter XI.M1, Program Description -"The Code of Federal Regulations, 10 CFR 50.55a, imposes the in-service inspection (ISI) requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI, for Class 1, 2, and 3 pressure-retaining components and their integral attachments in light-water cooled power plants. Inspection, repair, and replacement of these components are covered in Subsections IWB, IWC, and IWD, respectively, in the 1995 edition through the 1996 addenda."

The MNGP License Renewal ASME Section XI, ISI AMP is based on 10 CFR 50.55a and the 1995 edition through the 1996 addenda of ASME Section XI. However, within 10CFR 50.55a there are two codified exceptions that are utilized at MNGP, which allow a different ASME Section XI Edition or Addenda to be used. These were included as exceptions in the LRA since they do not meet the literal definition of this program as described in NUREG-1801, i.e., they are codified exceptions to "ASME Section XI, 1995 edition through 1996 addenda" and they are not subject to NRC review and approval in the same manner as plant specific relief requests in accordance with 10 CFR50.55a. As they are codified, it is possible they could extend into the license renewal period of operation.

Audit Question No.: B2.1.2-05

Source: **AMP Audit** **Status:** **Sufficient per NRC** **Author:** **Jackson** **MNGP Owner:** **Bill O'Brien** **Discipline:** **Mechanical**

Question:

For each of the following AMPs, the MNGP LRA says that the AMP "is part of the MNGP ASME Section XI In-Service Inspection Program":
·B2.1.2 ASME Section XI In-Service Inspection, Subsections IWB, IWC and IWD
·B2.1.3 ASME Section XI, Subsection IWF
·B2.1.9 BWR Penetrations
·B2.1.10 BWR Stress Corrosion Cracking
·B2.1.11 BWR Vessel ID Attachment Welds
·B2.1.12 BWR Vessel Internals

As part of its review of MNGP programs that are credited with fulfilling NUREG-1801 AMP requirements, MNGP would likely have created mappings of NUREG-1801 AMP requirements into MNGP ASME Section XI ISI Program requirements. If so, please make those mapping plus MNGP's ASME Section XI ISI Program documents available to support the on-site review of AMPs. If not, please provide additional information about how MNGP program requirements were compared against NUREG-1801 AMP requirements to reach the consistency conclusions stated in the LRA.

Date Received: 6/7/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response:

Mappings of NUREG-1801 AMP requirements into MNGP's ASME Section XI ISI Program requirements are included in MNGP Aging Management Program Basis Document, PBD-AMP-033, which will be available for review.

JPP 6/9/05

Final Response:

Mappings of NUREG-1801 AMP requirements into MNGP's ASME Section XI ISI Program requirements are included in MNGP aging management program basis document, which will be available for review.

Audit Question No.: B2.1.2-06

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question:

For B2.1.2 (ASME Section XI ISI, Subsections IWB, IWC & IWD) under Scope of Program, MNGP identifies two exceptions.

The first is that: "Per 10 CFR 50.55a(b)(2)(xi), the requirements of IWB-1220 in the 1989 Edition of ASME Section XI, 'Components Exempt from Examination', are used in Class 1 piping instead of the 1995 Edition of ASME Section XI with the 1996 Addenda."
QUESTION: What, if any, Class 1 piping required to be examined by the 1995 Edition & 1996 Addenda is exempted from examination by use of the 1989 Edition?

The second is that: "per 10 CFR 50.55a(b)(2)(xxi)(B), reused CRD bolting must meet examination requirements for Table IWB-2500-1, Category B-G-2, Item B7.80 of ASME Section XI 1995 Edition with 1995 Addenda."

QUESTION: What is the difference in examination requirements for reused CRD bolting between the 1995 Edition with 1995 Addenda and the 1995 Edition with 1996 Addenda?

Date Received: 6/7/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response:

1st Question - It is just the opposite; the 1995 Edition with the 1996 Addenda allows the exemption of welds or portion of welds that are inaccessible due to being encased in concrete, buried underground, located inside a penetration, or encapsulated by guard pipe, an exemption that is not included in the 1989 Edition. 10CFR50.55a(b)(2)(xi) does not allow this exemption to be used, hence the NRC limitation is applied requiring use of the 1989 Edition of Section XI.

2nd Question - The 1995 Edition with the 1996 Addenda does not contain the examination requirements for CRD bolting from Table IWB-2500-1. Therefore, no examinations are be required per the 1995 Edition with the 1996 Addenda. The NRC limitation in 10CFR50.55a(b)(2)(xxi)(B) specifies that, if you are going to re-use CRD bolting, then you must perform the examinations as specified in Table IWB-2500-1 of the 1995 Edition of Section XI.

JPP 6/10/05

Final Response:

1st Question - It is just the opposite; the 1995 Edition with the 1996 Addenda allows the exemption of welds or portion of welds that are inaccessible due to being encased in concrete, buried underground, located inside a penetration, or encapsulated by guard pipe, an exemption that is not included in the 1989 Edition. 10CFR50.55a(b)(2)(xi) does not allow this exemption to be used, hence the NRC limitation is applied requiring use of the 1989 Edition of Section XI.

2nd Question - The 1995 Edition with the 1996 Addenda does not contain the examination requirements for CRD bolting from Table IWB-2500-1. Therefore, no examinations are be required per the 1995 Edition with the 1996 Addenda. The NRC limitation in 10CFR50.55a(b)(2)(xxi)(B) specifies that, if you are going to re-use CRD bolting, then you must perform the examinations as specified in Table IWB-2500-1 of the 1995 Edition of Section XI.

Audit Question No.: B2.1.2-07

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question: There is overlap between this question and previous B2.1.2 question # 3. For MNGP AMPs B2.1.1, B2.1.9, B2.1.10, B2.1.11 and B2.1.12, the MNGP LRA describes ASME Section XI relief requests and/or implementation of RI-ISI as either not an exceptions to GALL or treats them as if they are not considered to be exceptions to GALL. Although these deviations from the requirements of ASME Section XI have been approved by the NRC for the current inspection interval, they would seem more appropriately to be categorized as exceptions to GALL. The technical basis which supported earlier NRC acceptance of these CLB changes for the current inspection interval may provide a basis for these deviations from ASME Section XI requirements being acceptable exceptions. However, their approval for the current inspection interval is not, per se, a basis for their being acceptable during the extended interval of operation. The applicant is asked to consider whether a different characterization of relief requests and RI-ISI in the MNGP LRA would be more appropriate.

Date Received: 6/7/2005 Potential Submittal on ☑ Potential LRA Update Required ☑ Assoc LRA Section - Appendix B

Draft Response: See response to RAI# B2.1.26-01.

Final Response: See response to RAI# B2.1.26-01.

Audit Question No.: B2.1.2-08

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question:

8. GALL suggests that "Thickness measurement of tank bottom surfaces is an acceptable verification program." to ensure that the effectiveness of the program is verified and to ensure that significant degradation is not occurring and the component intended function will be maintained. The LRA does not mention such a measurement. What is MNGP's alternative? 8. In NUREG-1801, the NDE techniques described in BWRVIP-03 (Reactor Pressure Vessel and Internals Examination Guidelines) are explicitly invoked for AMPs XI.M1 (ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD), XI.M4 (BWR Vessel ID Attachment Welds), XI.M8 (BWR Penetrations), and XI.M9 (BWR Vessel Internals). The 10 element description for each of these AMPs says under "Detection of Aging Effects" that: "The nondestructive examination (NDE) techniques appropriate for inspection of BWR vessel internals and their implementation needs, including the uncertainties inherent in delivering and executing NDE techniques in a BWR, are included in BWRVIP-03."

In the MNGP LRA for AMP B2.1.9 (BWR Penetrations) the "Detection of Aging Effects" says, "The guidelines in BWRVIP-03 are also being followed"; and for AMP B2.1.11 (BWR Vessel ID Attachment Welds) "Detection of Aging Effects" says, "The requirements of ASME Section XI Examination Category B-2 including the BWRVIP-03 and BWRVIP-48 guidelines for the reactor vessel interior attachments have been incorporated into the MNGP BWR Vessel ID Attachment Weld Program."

However, the LRA descriptions for MNGP AMP B2.1.2 (ASME Section XI In-Service Inspection, Subsections IWB, IWC and IWD) and for MNGP AMP B2.1.12 (BWR Vessel Internals) do not make reference to BWRVIP-03, nor clearly state that the guidelines of BWRVIP-03 are incorporated into these MNGP aging management programs.

MNGP is requested to provide a statement and discussion that clarifies whether the guidelines of BWRVIP-03 have been incorporated into MNGP AMPs B2.1.2 and B2.1.12 and other applicable MNGP AMPs.

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response:

The BWR Penetrations Program and the BWR Vessel ID Attachment Welds Program are part of the MNGP ASME Section XI Inservice Inspection Program. The guidelines of BWRVIP-03 are followed under the BWR Penetrations and BWR Vessel ID Attachment Welds Programs as well as the MNGP ASME Section XI Inservice Inspection Program and MNGP BWR Vessel Internals Program.

MNGP procedures for visual inspections state that when UT or ET are utilized, procedures shall be reviewed to the recommendations contained in the latest revision of BWRVIP-03.

JPP 6/10/05

Final Response:

The BWR Penetrations Program and the BWR Vessel ID Attachment Welds Program are part of the MNGP ASME Section XI Inservice Inspection Program. The guidelines of BWRVIP-03 are followed under the BWR Penetrations and BWR Vessel ID Attachment Welds Programs as well as the MNGP ASME Section XI Inservice Inspection Program and MNGP BWR Vessel Internals Program.

MNGP procedures for visual inspections state that when UT or ET are utilized, procedures shall be reviewed to the recommendations contained in the latest revision of BWRVIP-03.

Audit Question No.: B2.1.2-08a

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question: B2.1.2 PBD/AMP-033 states that: "The augmented inspection program for High Energy Line Break (HELB) includes 36 class 1 welds..." and that "independent of HELB, RI-ISI selected 3 of the 36 welds for examination" and that "the remaining welds will continue to be inspected in accordance with the HELB augmented inspection program." PBD/AMP-033 also states that MNGP is not committed to NUREG-0800 SRP.

QUESTIONS: What is the difference in technique and/or frequency between the HELB-related examinations and the RI-ISI-related examinations? Do the two inspection programs address the same aging effects at different levels of resolution or do they address different aging effects? Is MNGP committing to continue these inspections as described in the program basis document through the period of extended operation?

Date Received: 6/14/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: First a clarification to question 2 above: PBD/AMP-033, B2.1 states that 8 of the 36 welds have been selected for RI-ISI. In response to the question, both programs (HELB and ISI) require a volumetric exam of the subject welds to be performed once in a ten year time period (interval) and require a successive exam in each ten year time period that follows. The HELB exams are implemented via the ISI Program because ISI examination techniques fulfill the HELB examination requirements. Both programs address the same aging effect at the same resolution. MNGP HELB and ISI Programs continue through the period of extended operation.

Final Response: First a clarification to the question above: The MNGP program basis document for the ASME Section XI Inservice Inspections, Subsections IWB, IWC, and IWD aging management program states that 8 of the 36 welds have been selected for RI-ISI. In response to the question, both programs (HELB and ISI) require a volumetric exam of the subject welds to be performed once in a ten year time period (interval) and require a successive exam in each ten year time period that follows. The HELB exams are implemented via the ISI Program because ISI examination techniques fulfill the HELB examination requirements. Both programs address the same aging effect at the same resolution. MNGP HELB and ISI Programs continue through the period of extended operation.

Audit Question No.: B2.1.2-09

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question:

B2.1.2 MNGP LRA identifies as an exception to NUREG-1801 that the requirements of IWB-1220 in the 1989 Edition of ASME Section XI are used in Class 1 piping instead of the 1995 Edition with 1996 Addenda. In response to my earlier question about requirements of IWB-1220 in the 1989 Edition of ASME Section XI vs. requirements in the 1995 Edition with 1996 Addenda, MNGP says that the later edition and addenda allow an exemption of welds or portion of welds that are inaccessible ... and that an exemption is not included in the 1989 Edition.

Please explain how, programmatically, the requirements of the 1989 Edition are implemented. For example, the program includes requirements to inspect certain welds that are inaccessible at MNGP. What does MNGP do to fulfill this requirement? Please describe how this situation has been dealt with in the past and how it will be dealt with during the period of extended operation?

Date Received: 6/14/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response:

Programmatically, based on the NRC limitation in 10CFR50.55a to fulfill the requirements of IWB-1220 of the 1989 Edition, the inaccessible welds are included in the total population of eligible ISI welds at MNGP, from which examination population is selected. All eligible welds, including welds not permitted to be exempt from volumetric and surface exams by the 1989 Edition, are within the ASME Section XI Class 1 Reactor Coolant Pressure Boundary that is required to be pressure tested each refueling outage prior to plant startup per Table IWB-2500, Category B-P. The ISI Program has always been, and will continue to be in the extended period of operation, in compliance with the requirements set forth in 10CFR50.55a, including those that apply to inaccessible welds.

Final Response:

Programmatically, based on the NRC limitation in 10CFR50.55a to fulfill the requirements of IWB-1220 of the 1989 Edition, the inaccessible welds are included in the total population of eligible ISI welds at MNGP, from which examination population is selected. All eligible welds, including welds not permitted to be exempt from volumetric and surface exams by the 1989 Edition, are within the ASME Section XI Class 1 Reactor Coolant Pressure Boundary that is required to be pressure tested each refueling outage prior to plant startup per Table IWB-2500, Category B-P. The ISI Program has always been, and will continue to be in the extended period of operation, in compliance with the requirements set forth in 10CFR50.55a, including those that apply to inaccessible welds.

Audit Question No.: B2.1.2-10

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question: B2.1.2 Under Parameters Monitored/Inspected the MNGP LRA says: "The aging management parameters that are monitored/inspected are loss of material and crack initiation and growth, and reduction of fracture toughness."

Please identify to which components the aging effect "reduction of fracture toughness" applies. Also, explain more fully (or identify the regulatory basis) why inspections under ASME Section XI are adequate to detect and manage the aging effect "reduction of fracture toughness."

Date Received: 6/14/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Reduction of fracture toughness applies to Core Spray check valves AO-14-13A, B, and RHR check valves AO-10-46A, B, which are constructed of cast austenitic stainless steel exposed to reactor coolant.

NUREG 1801, item IV.C1.3-b states "The ASME Section XI inspection requirements are sufficient for managing the effects of loss of fracture toughness due to thermal aging embrittlement of CASS valve bodies."

Final Response: Reduction of fracture toughness applies to Core Spray check valves AO-14-13A and AO-14-13B, and RHR check valves AO-10-46A and AO-10-46B, which are constructed of cast austenitic stainless steel exposed to reactor coolant.

NUREG 1801, item IV.C1.3-b states "The ASME Section XI inspection requirements are sufficient for managing the effects of loss of fracture toughness due to thermal aging embrittlement of CASS valve bodies."

Audit Question No.: B2.1.2-11

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question:

B2.1.2 PBD/AMP-033 in Section 3.4 (Detection of Aging Effects), Subsection B says: "The MNGP ASME Section XI ISI, Subsections IWB, IWC and IWD Program implements the following activities that are in variance with aspects of the NUREG-1801 XI.M1 AMP regarding detection of aging effects. These variances are based on NRC approved relief requests and Code Cases." Nine separate variances are listed as line items in PBD/AMP-033. However, the MNGP LRA evaluation of AMP B2.1.2 lists only two exceptions to NUREG-1801.

QUESTIONS:
Are the two NUREG-1801 exceptions listed in the MNGP LRA for this AMP included in the nine variance line items listed in PBD/AMP-033? If so, please identify which of the nine line items they are?

Why are the remainder of the nine listed "variances" (except for the Code Cases being implemented as approved in Reg. Guide 1.147) not classified as "exceptions to NUREG-1801?" Should they be identified as exceptions to NUREG-1801 in the LRA?

For each of the nine line items, please provide additional discussion of how this variance affects the MNGP AMP credited to manage aging effects during the extended period of operation. Specifically, with this variance in place, what will not be done in the MNGP AMP that would be done if there were no variance from the AMP as described in NUREG-1801 XI.M1? What is being done in the MNGP AMP that would not be done if there were no variance from the AMP as described in NUREG-1801 XI.M1?

Date Received: 6/14/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response:

Response:
No, the two NUREG-1801 exceptions listed in the MNGP LRA for PBD/AMP-033 are not included in the nine variance line items listed in PBD/AMP-033.

Response:
The remainder of the nine listed variances are not classified as "exceptions to NUREG-1801". The first three items are enhancements to the MNGP ASME Section XI ISI Program that exceed the requirements of NUREG 1801, XI.M1, ASME Section XI Inservice Inspection Subsections IWB, IWC, and IWD. For the remaining relief requests per the Dresden/Quad Cities SER, NUREG 1796 "The staff position is that current Relief Requests granted by the staff have no bearing on License Renewal commitments, because the basis for the relief request and the period of time during which the relief request is applicable generally will not carry over to the period of extended operation. Consequently, for license renewal the staff expects a commitment to IWE and supplemental requirements consistent with 10 CFR 50.55a."

MNGP's position is consistent with the above staff position. The MNGP License Renewal ASME Section XI, ISI AMP will be in accordance with 10 CFR 50.55a, which includes the process for determining which relief requests and supplemental requirements apply. Relief Requests are subject to periodic review by the NRC under 10CFR 50.55a. It cannot be predicted which existing or new relief requests may be part of the future MNGP License Renewal AMP. However, MNGP will only implement modifications to the program during the extended period of operation as allowed by 10CFR50.55a.

Response:

Variance affects the MNGP AMP as follows:

(1) ASME Section XI Appendix VIII is being implemented as modified by 10 CFR 50.55a dated September 26, 2002 and approved relief requests.

Response: This activity enhances the volumetric examinations. The activity exceeds the requirements of NUREG 1801, XI.M1, ASME Section XI Inservice Inspection Subsections IWB, IWC, and IWD, and therefore is not an exception.

(2) The reactor vessel is being examined in accordance with Regulatory Guide 1.150, Ultrasonic Testing of Reactor Vessel Welds During Preservice and Inservice

Examinations, Revision 1, Generic Letter 83-15, Implementation of Reg. Guide 1.150, "Ultrasonic Testing of Reactor Vessel Welds During Preservice and Inservice Examinations, Revision 1" and approved relief requests.

Response: This guidance has been superceded by the activity described above and is no longer applicable.

(3) Per MEB 3-1 as amended by Generic Letter 87-11, Relaxation in Arbitrary Intermediate Pipe Rupture Requirements, high-energy line break piping is being 100% volumetrically examined each 10-year inspection interval.

Response: This activity enhances the number of examinations on the HELB lines. The activity exceeds the requirements of NUREG 1801, XI.M1, ASME Section XI Inservice Inspection Subsections IWB, IWC, and IWD, and therefore is not an exception.

The remainder of the variances are relief requests. Discussions of the impact of relief requests on the AMP are discussed in another RAI.

Final Response: Response:
No, the two NUREG-1801 exceptions listed in the MNGP LRA for the MNGP Program Basis Document for ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD are not included in the nine variance line items listed in the MNGP Program Basis Document for ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

Response:
The remainder of the nine listed variances are not classified as "exceptions to NUREG-1801". The first three items are enhancements to the MNGP ASME Section XI ISI Program that exceed the requirements of NUREG 1801, XI.M1, ASME Section XI Inservice Inspection Subsections IWB, IWC, and IWD. For the remaining relief requests per the Dresden/Quad Cities SER, NUREG 1796 "The staff position is that current Relief Requests granted by the staff have no bearing on License Renewal commitments, because the basis for the relief request and the period of time during which the relief request is applicable generally will not carry over to the period of extended operation. Consequently, for license renewal the staff expects a commitment to IWE and supplemental requirements consistent with 10 CFR 50.55a."

MNGP's position is consistent with the above staff position. The MNGP License Renewal ASME Section XI, ISI AMP will be in accordance with 10 CFR 50.55a, which includes the process for determining which relief requests and supplemental requirements apply. Relief Requests are subject to periodic review by the NRC under 10CFR 50.55a. It cannot be predicted which existing or new relief requests may be part of the future MNGP License Renewal AMP. However, MNGP will only implement modifications to the program during the extended period of operation as allowed by 10CFR50.55a.

Response:

Variance affects the MNGP AMP as follows:

(1) ASME Section XI Appendix VIII is being implemented as modified by 10 CFR 50.55a dated September 26, 2002 and approved relief requests.

Response: This activity enhances the volumetric examinations. The activity exceeds the requirements of NUREG 1801, XI.M1, ASME Section XI Inservice Inspection Subsections IWB, IWC, and IWD, and therefore is not an exception.

(2) The reactor vessel is being examined in accordance with Regulatory Guide 1.150, Ultrasonic Testing of Reactor Vessel Welds During Preservice and Inservice Examinations, Revision 1, Generic Letter 83-15, Implementation of Reg. Guide 1.150, "Ultrasonic Testing of Reactor Vessel Welds During Preservice and Inservice Examinations, Revision 1" and approved relief requests.

Response: This guidance has been superceded by the activity described above and is no longer applicable.

(3) Per MEB 3-1 as amended by Generic Letter 87-11, Relaxation in Arbitrary Intermediate Pipe Rupture Requirements, high-energy line break piping is being 100% volumetrically examined each 10-year inspection interval.

Response: This activity enhances the number of examinations on the HELB lines. The activity exceeds the requirements of NUREG 1801, XI.M1, ASME Section XI Inservice Inspection Subsections IWB, IWC, and IWD, and therefore is not an exception.

The remainder of the variances are relief requests. Discussions of the impact of relief requests on the AMP are discussed in another RAI.

Audit Question No.: B2.1.2-12

Source: **AMP Audit** **Status:** **Sufficient per NRC** **Author:** **Jackson** **MNGP Owner:** **Bill O'Brien** **Discipline:** **Mechanical**

Question: PBD/AMP033, Paragraph 3.3.B says, "The aging management parameters that are monitored/inspected are loss of material, crack initiation and growth, and reduction of fracture toughness as indicated in Table 7.1." However, Table 7.1 does not list "loss of material" as an aging effect managed by this AMP.

QUESTION:
Is loss of material one of the aging effects managed by this AMP?

Date Received: 6/16/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The ASME Section XI ISI AMP is not credited for managing loss of material in the LRA. The project document should be revised to eliminate "loss of material".

Final Response: The ASME Section XI ISI AMP is not credited for managing loss of material in the LRA. The project document should be revised to eliminate "loss of material".

Audit Question No.: B2.1.2-13

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question:

Risk-Informed In-Service Inspection (RI-ISI) is not included in any of the aging management programs evaluated in NUREG-1801. However, in MNGP LRA Sections A2.1.2, B2.1.1, B.1.9, B2.1.10 and possibly other sections, RI-ISI is identified as a feature of the current ASME Section XI Programs. Monticello's current operating license expires at midnight on September 8, 2010. The 10 year period applicable for Monticello's current inspection interval would end on May 31, 2012.

QUESTION:
If Monticello becomes licensed for operation in an extended period of operation beyond September 8, 2010, then what is MNGP's intention with regard to continued implementation of RI-ISI in the extended operating period after September 8, 2010, but before May 31, 2012? Will RI-ISI continue to be included in MNGP's Section XI Programs during this time period? If so, should use of RI-ISI in the extended period of operation be identified as an exception to NUREG-1801 in the AMPs where the ASME Section XI Program is credited? How will the MNGP LRA be revised?

Date Received: 6/17/2005 Potential Submittal on ☑ Potential LRA Update Required ☑ Assoc LRA Section - Appendix B

Draft Response: See response to RAI# B2.1.26-01.

Final Response: See response to RAI# B2.1.26-01.

Audit Question No.: B2.1.2-14

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Bill Roman **Discipline:** Programs

Question:

B2.1.2 In MNGP LRA discussion of Scope of Program for this AMP, seven (7) systems are listed as having components whose aging is managed by this program. These system appear to be systems that have direct interfaces with the reactor pressure vessel (RPV).

QUESTION:
What about other systems whose piping directly interfaces with the RPV (e.g., main steam system, feedwater system) or which comprises part of the reactor coolant pressure boundary but which may not directly interface with the RPV (e.g.,, the high pressure coolant injection system, the reactor core isolation cooling system, standby liquid control system)? Are components of these (and similar) systems also included in the program?

Date Received: 7/20/2005 Potential Submittal on ☑ Potential LRA Update Required ☑ Assoc LRA Section - B2.1.2

Draft Response:

The majority of the reactor coolant piping in the Main Steam, Feedwater, High Pressure Coolant Injection and Reactor Core Isolation Cooling Systems is carbon steel and not susceptible to cracking and therefore would not credit the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. There is some small bore stainless steel Class 1 piping in these systems. The piping is managed for cracking with Plant Chemistry and the One Time Inspection Program and references NUREG-1801 item V.D2.1-c. The One Time Inspection Program is credited instead of the BWRSCC Program since the BWRSCC Program does not cover small bore piping.

The LRA Table 3.3.2-17 Auxiliary Systems - Standby Liquid Control System, Page 3-487, needs to be revised to include the aging effect Cracking for stainless steel piping exposed to treated water, crediting the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, Plant Chemistry, and One-Time Inspection Programs.

Final Response:

The majority of the reactor coolant piping in the Main Steam, Feedwater, High Pressure Coolant Injection and Reactor Core Isolation Cooling Systems is carbon steel and is not susceptible to cracking and therefore, would not credit the ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD Program. There is some small bore stainless steel Class 1 piping in these systems. This piping is managed for cracking with the Plant Chemistry Program and the One-Time Inspection Program and references NUREG-1801 line item V.D2.1-c for components in GALL Chapters V (ESF) and VIII (SPC). The One-Time Inspection Program is credited instead of the BWRSCC Program since the BWRSCC Program does not address small bore piping. For Chapter IV (RCS) piping, the ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD Program, Plant Chemistry Program and One-Time Inspection Program are credited for managing cracking and reference NUREG-1801 line item IV.C1.1-i.

After further review of these systems, it was determined that a stainless steel piping segment in a treated water environment in the Standby Liquid Control System has the potential for cracking due to its proximity to the RPV. This segment is line number CH2-1 ½"-ECB to the RPV nozzle and is shown on LR-36253 (B,8). LRA Table 3.3.2-17 Auxiliary Systems - Standby Liquid Control System, Page 3-487, will be revised to include the aging effect of Cracking for this stainless steel piping with an internal treated water environment, crediting the ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD, Plant Chemistry and One-Time Inspection Programs. This will be NUREG-1801, Volume 2 Line Item IV.C1.1-i and Table 1 Item 3.1.1-7. Additionally, AMR-SLC, Revision 1, Standby Liquid Control System, shall be added to Table 7.2, Aging Management Review Reports, of the Aging Management Program Basis Document, PBD/AMP-033, ASME Section XI Inservice Inspection Subsections IWB, IWC, and IWD.

Audit Question No.: B2.1.26-02

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Madalin O'Brien **Discipline:** Civil

Question: The MNGP LRA contains no explicit statement with regard to current relief requests approved in accordance with 10 CFR 50.55a for the current inspection interval. What is Monticello's intention or expectation with regard to those relief requests during the extended period of operation? Will the relief granted by those requests be continued into the extended period of operation as part of the affected AMPs? I.E., is the relief granted by those requests credited in the MNGP LRA as a feature of the affected AMP(s)?

Date Received: 6/17/2005 Potential Submittal on ☑ Potential LRA Update Required ☑ Assoc LRA Section - Appendix B

Draft Response: See response to question B2.1.26-01.

Final Response: See response to question B2.1.26-01.

Audit Question No.: B2.1.3-01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Madalin O'Brien **Discipline:** Civil

Question:

1. MNGP LRA Evaluation of AMP B2.1.3 (ASME Section XI Subsection IWF) says that "The MNGP ASME Section XI, Subsection IWF Program will be enhanced to provide inspections of Class MC components supports consistent with NUREG-1801, Chapter III, Section B1.3."

QUESTIONS

a) Does the mean that metal containment (Class MC) supports will be added to the program where previously they were not included? Or, does it mean that for previously included MC supports the inspection techniques will be revised? Or, both?

b) I would like to see (or have summarized) the "before" and "after" MNGP procedure requirements or data sheets that implement this enhancement.

Date Received: 6/6/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response:

The current MNGP IWF Program does not include examinations of MC supports.

The current MNGP IWE Program includes general visual examinations of MC components and their supports in accordance with ASME Section XI, Table IWE-2500-1.

The following MC supports are included in examinations conducted under the current MNGP IWE Program.

- Torus/ring header seismic restraints
- Drywell male and female stabilizers
- Shield stabilizers
- Torus columns
- Torus saddles
- Vent header columns
- Downcomer bracing

For the period of extended operation, the MNGP License Renewal ASME Section XI, Subsection IWF Program will perform the VT-3 examination of MC supports listed above in accordance with ASME Section XI, Table IWF-2500-1 in compliance with the in-service inspection requirements of the 1995 Edition with the 1996 Addenda of Section XI.

For the period of extended operation, the MNGP License Renewal ASME Section XI, Subsection IWE Program will continue to perform the general visual examination of MC components and their supports listed above in accordance with ASME Section XI, Table IWE-2500-1.

Final Response:

The current MNGP IWF Program does not include examinations of MC supports.

The current MNGP IWE Program includes general visual examinations of MC components and their supports in accordance with ASME Section XI, Table IWE-2500-1.

The following MC supports are included in examinations conducted under the current MNGP IWE Program.

- Torus/ring header seismic restraints
- Drywell male and female stabilizers
- Shield stabilizers
- Torus columns

Torus saddles
Vent header columns
Downcomer bracing

For the period of extended operation, the MNGP License Renewal ASME Section XI, Subsection IWF Program will perform the VT-3 examination of MC supports listed above in accordance with ASME Section XI, Table IWF-2500-1 in compliance with the in-service inspection requirements of the 1995 Edition with the 1996 Addenda of Section XI.

For the period of extended operation, the MNGP License Renewal ASME Section XI, Subsection IWE Program will continue to perform the general visual examination of MC components and their supports listed above in accordance with ASME Section XI, Table IWE-2500-1.

Audit Question No.: B2.1.3-02

Source: **AMP Audit** **Status:** **Sufficient per NRC** **Author:** **Jackson** **MNGP Owner:** **Madalin O'Brien** **Discipline:** **Civil**

Question: 2. With reference to MNGP AMP B2.1.3 (ASME Section XI, Subsection IWF): For Class 1 piping and component supports, Subsection IWF (1989 edition) refers to Subsection IWB for the inspection scope and schedule.

· According to Table IWB-2500-1, only 25% of nonexempt supports are subject to examination. Supports exempt from examination are the supports for piping systems that are exempt from examination, according to pipe diameter or service.
· The same supports are inspected in each 10-year inspection interval.

Although the MNGP LRA does provide general confirmation that the AMP is in accordance with requirements of ASME Section XI, 1995 Edition through 1996 Addenda, please provide confirmation that it is in accordance with these specific criteria.

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: As the question is understood, MNGP examines non-exempt Class 1 piping supports in accordance with Table IWF-2500-1, which specifies the extent of examination as 25% for each inspection interval. To the extent practical, the same supports selected for examination during the first inspection interval shall be examined during each successive inspection interval.

Final Response: As the question is understood, MNGP examines non-exempt Class 1 piping supports in accordance with Table IWF-2500-1, which specifies the extent of examination as 25% for each inspection interval. To the extent practical, the same supports selected for examination during the first inspection interval shall be examined during each successive inspection interval.

Audit Question No.: B2.1.3-03

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Madalin O'Brien **Discipline:** Civil

Question: 3. With reference to MNGP AMP B2.1.3 (ASME Section XI, Subsection IWF): For Class 2, 3, and MC piping and component supports, Subsection IWF (1989 edition) refers to Subsections IWC, IWD, and IWE for the inspection scope and schedule.

· According to Table IWC-2500-1, 7.5% of nonexempt supports are subject to examination for Class 2 systems.
· The same supports are inspected in each 10-year inspection interval

Although the MNGP LRA does provide general confirmation that the AMP is in accordance with requirements of ASME Section XI, 1995 Edition through 1996 Addenda, please provide confirmation that it is in accordance with these specific criteria.

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: As the question is understood, MNGP examines non-exempt Class 2 and 3 piping supports and supports other than piping supports in accordance with Table IWF-2500-1, which specifies the extent of examination as 15%, 10%, and 100% respectively for each inspection interval. To the extent practical, the same supports selected for examination during the first inspection interval shall be examined during each successive inspection interval.

Final Response: As the question is understood, MNGP examines non-exempt Class 2 and 3 piping supports and supports other than piping supports in accordance with Table IWF-2500-1, which specifies the extent of examination as 15%, 10%, and 100% respectively for each inspection interval. To the extent practical, the same supports selected for examination during the first inspection interval shall be examined during each successive inspection interval.

Audit Question No.: B2.1.3-04

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Madalin O'Brien **Discipline:** Civil

Question: 4. With reference to MNGP AMP B2.1.3 (ASME Section SI, Subsection IWF): Under Parameters Monitored or Inspected, the MNGP LRA describes the aging effect parameters that are monitored or inspected as "loss of material and loss of mechanical function." NUREG-1801 provides a more detailed listing of specific examinations from IWF-2500.

The Applicant is asked either to provide confirmation that the MNGP AMP does include the specific examinations listed in NUREG-1801 or have available during the audit implementing instructions that confirm these specific examinations are included.

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: MNGP License Renewal ASME Section XI, Subsection IWE Program implementing procedure PEI-02.05.02, Visual Examination of Components and Their Supports, includes parameters inspected consistent with those provided in NUREG-1801, XI.S3, ASME Section XI, Subsection IWF Program for IWF-2500.

Final Response: MNGP License Renewal ASME Section XI, Subsection IWE Program implementing procedure entitled, Visual Examination of Components and Their Supports, includes parameters inspected consistent with those provided in NUREG-1801, XI.S3, ASME Section XI, Subsection IWF Program for IWF-2500.

Audit Question No.: B2.1.3-05

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Madalin O'Brien **Discipline:** Civil

Question:

B2.1.3, "ASME SECTION XI, Subsection IWF
ADDITIONAL QUESTIONS FOR MONTICELLO LICENSE RENEWAL STAFF (06/15/2005):

1. NUREG-1801, Section XI.S3, ASME Section XI, Subsection IWF, states that "ASME Code Subsection IWF constitutes an existing mandated program applicable to managing aging of ASME Class 1, 2, 3 and MC supports for license renewal." It also says that, "Starting with the 1990 addenda to the 1989 edition, the scope of Subsection IWF was revised. The percentage of each type of nonexempt support subject to examination were incorporated into Table IWF-2500-1. The revised percentages are 25% of Class 1 nonexempt piping supports, 15% of Class 2 nonexempt piping supports, 10% of Class 3 non exempt piping supports, and 100% of supports other than piping supports (Class 1, 2, 3, and MC)."

MNGP engineering work instruction EWI-09.04.00 (ASME Section XI Inservice Inspection Program, Revision 0) applies to ASME pressure retaining components and to ASME Class 1, 2, and 3 components supports; but it does not apply to Class MC component supports.

MNGP LRA AMP description for B2.1.3 (ASME Section XI, Subsection IWF) says that, "The MNGP ASME Section XI, Subsection IWF Program will be enhanced to provide inspection of Class MC component supports consistent with NUREG 1801, Chapter III, Section B1.3."

NUREG 1801, Chapter II, Section B1.3 contains two line items, B1.3.1-a and B1.3.1-b, where ASME Section XI, Subsection IWF is identified as an acceptable aging management program.

For supports other than piping supports, ASME Section XI, Table IWF-2500-1 allows that, "For multiple components other than piping, within a system of similar design, function and service, the supports of only one of the multiple components are required to be examined."

QUESTIONS:
When enhanced as described in MNGP LRA, will this AMP provide for inspection of all MNGP Class MC supports rolled up into line items B1.3.1-a and B1.3.1-b to the extent required by ASME Section XI, Table IWF-2005-1, Edition 1995 through 1996 Addenda?

If not, please described which Class MC supports are not included and provide the technical basis on which they are not included.

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Response: Yes: When the ASME Section XI, Subsection IWF Program is enhanced, all MNGP MC supports (See response to Question B2.1.3-01 for complete list of MC supports) will be rolled up into NUREG-1801 line items III.B1.3.1-a, III.B1.3.2-a and III.B1.3.3-a to the extent required by ASME Section XI, Table IWF-2500-1. NUREG-1801 item III.B1.3.1-b is a TLAA and the evaluation can be found in Section 4 of the LRA.

Final Response: Response: Yes: When the ASME Section XI, Subsection IWF Program is enhanced, all MNGP MC supports (See response to Question B2.1.3-01 for complete list of MC supports) will be rolled up into NUREG-1801 line items III.B1.3.1-a, III.B1.3.2-a and III.B1.3.3-a to the extent required by ASME Section XI, Table IWF-2500-1. NUREG-1801 item III.B1.3.1-b is a TLAA and the evaluation can be found in Section 4 of the LRA.

Audit Question No.: B2.1.9-01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question:

For MNGP AMP B2.1.9 (BWR Penetrations), under Operating Experience the LRA says that the SLC nozzle safe end and jet pump instrument nozzle safe end and penetration seals were replaced in 1984 with IGSCC resistant material.

QUESTION: Had any cracking been detected in these components before replacement? Or, was this simply a preventive measure? Has any cracking been detected since?

REQUEST: I would like to have a list of implementing procedures for this AMP identified and available, plus access to the procedures for review, if needed, during the on-site audit..

Date Received: 6/7/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response:

The replacements of the jet pump instrument nozzle safe-end, SLC nozzle safe-end, and the penetration seals were completed as a preventive measure, not for cracking issues. There has been no cracking detected since the replacement.

BWR Penetrations AMP Implementing Instructions and Procedures:

4 AWI-09.04.00 Inservice Inspection Licensee Control Program
4 AWI-09.04.03 ASME Section XI Repair/Replacement Program
4 AWI-07.03.01 Nondestructive Examination
Inservice Inspection Examination Plan Fourth Interval May 1, 2003 through May 31, 2012
II.05 Chemistry Limits and Sampling Frequency
EWI-08.01.01 Boiling Water Reactor Vessel Internals Project (BWRVIP) Administrative Manual
EWI-08.01.02 BWR Implementation Guidelines
EWI-09.04.00 ASME Section XI Inservice Inspection Program
II.01 Strategic Chemistry Plan
PEI-02.08.03 Inservice Inspection Flaw Evaluation
NSP Project E-84N625, Reactor Vessel Head Nozzle Clad, October, 1984

JPP 6/10/05

Final Response:

The replacements of the jet pump instrument nozzle safe-end, SLC nozzle safe-end, and the penetration seals were completed as a preventive measure, not for cracking issues. There has been no cracking detected since the replacement.

BWR Penetrations aging management program implementing procedures were provided to the NRC auditor during the MNGP on-site audit conducted the week of June 13, 2005 for on-site review by the auditor.

Audit Question No.: B2.1.9-02

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question:

PBD/AMP-039 says that, "The control rod drive stub tubes were evaluated as a result of the Significant Event Report SER 83-003 entitled "Cracks in Control Rod Drive Stub Tubes," January 19, 1983. It was concluded that cracks due to IGSCC in the CRD stub tubes are unlikely because the MNGP stub tubes and weld material are inconel. Although inconel can be susceptible to IGSCC, a creviced geometry is necessary to initiate cracks and this geometry does not exist in the reactor pressure vessel design at MNGP."

QUESTION:
Has MNGP confirmed by inspection that cracks have not occurred in the control rod drive stub tubes and associated welds?

Is inspection of control rod drive stub tubes and associated welds included in the MNGP ISI program?

Is any additional activity, beyond the evaluation described in PBD/AMP-039, required to manage aging effects on control rod drive stub tubes and associated welds during the extended period of operation?

Date Received: 6/16/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response:

a. No recordable indications have ever been found on the control rod drive stub tubes. The tubes have been examined under Examination Category B-N-2 internally when accessible and under Examination Category B-P externally every outage.

b. Control rod drive stub tubes are inspected in the ASME Section XI, ISI Program under Examination Categories B-N-2 and B-P.

c. As stated above the control rod drive stub tubes are inspected in the ASME Section XI, ISI Program under Examination Categories B-N-2. These are not described under the BWR Penetrations AMP, as these inspections are conducted on the interior of the reactor vessel, but are described in the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP. There are no additional activities for managing aging of the control rod drive stub tubes.

JPP 6/20/05

Final Response:

a. No recordable indications have ever been found on the control rod drive stub tubes. The tubes have been examined under Examination Category B-N-2 internally when accessible and under Examination Category B-P externally every outage.

b. Control rod drive stub tubes are inspected in the ASME Section XI, ISI Program under Examination Categories B-N-2 and B-P.

c. As stated above the control rod drive stub tubes are inspected in the ASME Section XI, ISI Program under Examination Categories B-N-2. These are not described under the BWR Penetrations AMP, as these inspections are conducted on the interior of the reactor vessel, but are described in the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP. There are no additional activities for managing aging of the control rod drive stub tubes.

Audit Question No.: B2.1.9-03

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question: PBD/AMP-039 says that, "Code inspection are enhanced with inspections consistent with the requirements of BWRVIP-27 and BWRVIP-49 and an NRC approved alternative (RI-ISI)."

QUESTION:
With regard to aging management of BWR Penetrations, please describe the effects on this program introduced by MNGP's implementation of RI-ISI.

Date Received: 6/16/2005 Potential Submittal on ☑ Potential LRA Update Required ☑ Assoc LRA Section - Appendix B

Draft Response: RI-ISI reduced the number of welds being inspected for ASME Section XI, ISI, Examination Categories B-F and B-J. The welds were selected based on their susceptibility to aging mechanisms and the consequences of their failure rather than the ASME Section XI ISI required sample population.

Final Response: See response to RAI# B2.1.26-01.

RI-ISI reduced the number of welds being inspected for ASME Section XI, ISI, Examination Categories B-F and B-J. The welds were selected based on their susceptibility to aging mechanisms and the consequences of their failure rather than the ASME Section XI ISI required sample population.

Audit Question No.: B2.GEN-01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Bill O'Brien **Discipline:** Programs

Question:

Generic - In several AMP descriptions and in related USAR supplement paragraphs, the MNGP LRA refers to "approved relief requests" and/or "risk-informed ISI" which have been approved for the current 10-year operating interval. Typically the wording in the MNGP LRA is something like "Exception to ASME requirements that have been granted by approved Code Cases or relief request are not considered to be an exception to NUREG-1801."

Contrary to the statement in the MNGP LRA, the GALL Report does not recognize RI-ISI programs as an alternative to the current ASME Section XI ISI requirements and the NRC staff does consider implementation of a currently approved RI-ISI program (or any other currently approved relief request that affects an AMP program element) during the period of extended operation to be an exception to the affected AMP program element(s).

QUESTION:
How does MNGP propose to revise the LRA with regard to its characterization of exceptions to ASME requirements that have been granted for the current inspection interval by approved Code Cases, relief-requests and/or risk-informed ISI?

Date Received: 7/20/2005 Potential Submittal on ☑ Potential LRA Update Required ☑ Assoc LRA Section - B2

Draft Response: See response to RAI# B2.1.26-01.

Final Response: See response to RAI# B2.1.26-01.

Audit Question No.: B3.2-04

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Mike Aleksey **Discipline:** Programs

Question:

B3.2 – NMC Letter L-MT-05-052 dated June 10, 2005, to US NRC, "Response to Request for Additional Information and Submittal of Additional Information in Support of the Monticello License Renewal Application (TAC No. MC6440), provides a revision to MNGP LRA Appendix A, USAR Supplement, Section A2.1, Aging Management Programs. For AMPs where an existing MNGP program is being enhanced for the period of extended operation, this revision to MNGP LRA Appendix A provides a statement of the commitment required to implement the enhancement.

MNGP AMP B3.2, Metal Fatigue of the Reactor Coolant Pressure Boundary, also includes an enhancement to "incorporate requirement for inclusion of NUREG/CR-6260 locations in implementing procedures for the MNGP Thermal Fatigue Monitoring Program."

QUESTION:
Will there also be a revision to MNGP LRA Appendix A, Section A4.2, Metal Fatigue of Reactor Coolant Pressure Boundary, to show the enhancement to MNGP AMP B3.2 as an explicit commitment?

Date Received: 7/20/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - B3.2

Draft Response:

The USAR Supplement, transmitted by NMC letter No. L-MT-05-052 on June 10, 2005, was in response to the staffs RAI A2.1-1. This RAI requested a list of commitments that were provided in the LRA transmittal letter as well as a schedule for implementation. The MNGP response specifically addressed Appendix A Section A2 AMPs only. In retrospect, inclusion of commitments from TLAA supporting activities (Section A4) would have provided a more comprehensive reply to the RAI. Although AMP B3.2 does not contain an explicit commitment in the AMP description, the commitment is satisfactorily described in Section A5 of the USAR Supplement (Item 52).

Consequently, MNGP does not intend to revise the June 10th letter to include an additional commitment description with the AMP description in Section A4 of LRA Appendix A until the first annual update of the LRA. If a revision to the LRA precedes the annual update this item will be included.

Final Response:

The USAR Supplement, transmitted by NMC letter No. L-MT-05-052 on June 10, 2005, was in response to the staffs RAI A2.1-1. This RAI requested a list of commitments that were provided in the LRA transmittal letter as well as a schedule for implementation. The MNGP response specifically addressed Appendix A Section A2 AMPs only. In retrospect, inclusion of commitments from TLAA supporting activities (Section A4) would have provided a more comprehensive reply to the RAI. Although AMP B3.2 does not contain an explicit commitment in the AMP description, the commitment is satisfactorily described in Section A5 of the USAR Supplement (Item 52).

Consequently, MNGP does not intend to revise the June 10th letter to include an additional commitment description with the AMP description in Section A4 of LRA Appendix A until the first annual update of the LRA. If a supplement to the LRA precedes the annual update this item will be considered for inclusion.

Audit Question No.: B3.2-1

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Mike Aleksey **Discipline:** Programs

Question:

For MNGP AMP B3.2 (Metal Fatigue of the Reactor Coolant Pressure Boundary), the LRA says that the existing fatigue monitoring program will be enhanced to incorporate requirements for inclusion of NUREG/CR-6260 locations in implementing procedures for the MNGP Thermal Fatigue Monitoring Program. The GALL states that the sample of critical components selected in NUREG/CR-6260, as a minimum, should be evaluated by applying environmental correction factors.

QUESTIONS:
Does MNGP have plant-specific locations that have or are projected to have higher cumulative usage factors (CUFs) than those components identified in NUREG/CR-6260. What process has MNGP implemented to ensure that any plant specific locations with higher CUFs are included within the scope of AMP B3.2? What are the criteria for identifying components and/or locations included in the monitoring and trending of AMP B3.2?

Date Received: 6/2/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - B3.2.1

Draft Response:

Yes, MNGP does have other areas that are projected to have cumulative fatigue usage values higher than locations evaluated for NUREG/CR-6260 locations. They are identified in the LRA and have been identified as acceptable in accordance with 10 CFR 54.21(c)(1) iii, "The effects of aging on the intended function(s) will be adequately managed for the period of extended operation." These items have been committed to by inclusion in the LRA. The MNGP Fatigue Monitoring Program will be revised to include these locations as well as the NUREG/CR-6260 locations. Fatigue evaluations conducted in accordance with this program are conducted on a once per cycle basis and are projected to a 60 year end-of-life (eol). If any locations are projected to exceed the code acceptance criteria for fatigue, appropriate actions will be taken to correct the situation prior to its occurrence. Corrective actions include, but are not limited to, improved transient monitoring, refined analyses, and physical modification to the affected location.

Final Response:

Yes, MNGP does have other areas that are projected to have cumulative fatigue usage values higher than locations evaluated for NUREG/CR-6260 locations. They are identified in the LRA and have been identified as acceptable in accordance with 10 CFR 54.21(c)(1) iii, "The effects of aging on the intended function(s) will be adequately managed for the period of extended operation." These items have been committed to by inclusion in the LRA. The MNGP Fatigue Monitoring Program will be revised to include these locations as well as the NUREG/CR-6260 locations. Fatigue evaluations conducted in accordance with this program are conducted on a once per cycle basis and are projected to a 60 year end-of-life (eol). If any locations are projected to exceed the code acceptance criteria for fatigue, appropriate actions will be taken to correct the situation prior to its occurrence. Corrective actions include, but are not limited to, improved transient monitoring, refined analyses, and physical modification to the affected location.

Audit Question No.: B3.2-2

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Mike Aleksey **Discipline:** Programs

Question:

With reference to MNGP AMP B3.2 (Metal Fatigue of the Reactor Coolant Pressure Boundary): NUREG-1801, Section X.M1 (Metal Fatigue of Reactor Coolant Pressure Boundary) under program element 3, Parameters Monitored/Inspected, allows that in lieu of monitoring the number of plant transients, "more detailed local monitoring of the plant transient may be used to compute the actual fatigue usage for each transient." Some other nuclear plants of similar vintage to Monticello, in their license renewal application, have identified implementation of fatigue monitoring using FatiguePro as a more detailed method of local monitoring that will be required during the extended period of operation. The MNGP LRA discussion of fatigue monitoring does not suggest that a requirement for more detailed local monitoring is anticipated during the extended period of operating.

QUESTIONS: On the basis of their fatigue monitoring to date, does MNGP estimate that any in-scope components will approach their fatigue limits during the extended period of operation? If not, is this because there have been relatively fewer transients at Monticello than at other BWRs of similar vintage (e.g., Dresden & Quad Cities). Or, is it because Monticello's fatigue monitoring program already includes relatively detailed local monitoring (such as the example with the feedwater nozzle cited under Operating Experience suggests)? How close to fatigue limits would MNGP allow components to approach before consideration of a more detailed method of local monitoring?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - B.3.2

Draft Response:

As identified in LRA Section 4 (TLAAs), all locations for fatigue consideration have been shown to have reasonable margin to allowable (1.0) when projected to the end of the LR term of operation (60 years). Although MNGP views these evaluations as conservative, we are considering implementation of a computerized transient data gathering and fatigue evaluation tool to more accurately assess the impact of these transients in the event that increased margin becomes necessary due to an unplanned event. We expect to complete this internal evaluation and begin implementation, if deemed appropriate, this year (2005).

Final Response:

As identified in LRA Section 4 (TLAAs), all locations for fatigue consideration have been shown to have reasonable margin to allowable (1.0) when projected to the end of the LR term of operation (60 years). Although MNGP views these evaluations as conservative, we are considering implementation of a computerized transient data gathering and fatigue evaluation tool to more accurately assess the impact of these transients in the event that increased margin becomes necessary due to an unplanned event. We expect to complete this internal evaluation and begin implementation, if deemed appropriate, this year (2005).

Audit Question No.: B3.2-3

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Mike Aleksey **Discipline:** Programs

Question: With reference to MNGP AMP B3.2 (Metal Fatigue of the Reactor Coolant Pressure Boundary): MNGP LRA in "Detection of Aging Effects" says, "this program projects fatigue usage through the end of the period of extended operation." Please provide information about which components are projected to be closest to their design limit at the end of the period of extended operation? What are their projected CUFs? What sort of assumptions are used in making the projections; for example, is it something like a simple scaling up by time or number of operating cycles from the current values? Or, is there an assumption that the rate of occurrence of fatigue inducing transients will be lower in the future than in the past?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - B3.2

Draft Response: LRA Section 4 identifies limiting locations, current and projected fatigue usages, and summary information relating to methodology.

Final Response: LRA Section 4 identifies limiting locations, current and projected fatigue usages, and summary information relating to methodology.

Audit Question No.: B3.2-4

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Jackson **MNGP Owner:** Mike Aleksey **Discipline:** Programs

Question:

NUREG-1801, Section X.M1, Metal Fatigue of Reactor Coolant Pressure Boundary, states that the AMP addresses the effects of the coolant environment on component fatigue life by assessing the impact of the reactor coolant environment on a sample of critical components that includes, as a minimum, those components selected in NUREG/CR-6260. In discussion with MNGP personnel (M. Aleksey), the audit team learned that the MNGP AMP B3.2, Metal Fatigue of the Reactor Coolant Pressure Boundary, intends to apply environmental corrections for only those components listed in NUREG/CR-6260 at this time.

MNGP is asked to provide additional discussion of why environmental corrections are applied only for the components listed in NUREG/CR-6260 and whether application of environmental correction factors to only this limited set of components provides reasonable assurance that AMP B3.2 will ensure fatigue design limits are not exceeded during the extended operating period for all RCPB components.

Date Received: 6/14/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response:

The identification of component locations in NUREG/CR-6260, which were used by MNGP, were based on an industry review of locations with generally high fatigue usage and/or importance from a risk perspective. NUREG/CR-6260 notes that these locations are not necessarily those with the highest fatigue usage however, as a group they are considered an adequate sample of locations for environmental fatigue evaluations if all evaluations are shown to be in compliance with fatigue acceptance criteria (i.e. U<1.0).

Implicit in this conclusion is the recognition that although these locations are not necessarily the highest in terms of fatigue, they are reasonably high to be representative since the associated fatigue analyses contain the conservatisms similar to those used for other locations. It is often necessary, as in the case of MNGP, to take credit for some of these conservatisms to comply with fatigue acceptance criteria.

In conclusion, if any environmental fatigue evaluation exceeds the acceptance criteria for the 60 year extended operating period consideration of other locations is required. For MNGP, all locations identified in NUREG/CR-6260 as representative for plants like MNGP have been evaluated and found to meet environmental fatigue acceptance criteria (see LRA Section 4.5). As a result, the current environmental fatigue evaluations which have been projected to the end of the license renewal term of operation (60 years), are adequate for plant representation without augmentation to other locations.

Final Response:

The identification of component locations in NUREG/CR-6260, which were used by MNGP, were based on an industry review of locations with generally high fatigue usage and/or importance from a risk perspective. NUREG/CR-6260 notes that these locations are not necessarily those with the highest fatigue usage however, as a group they are considered an adequate sample of locations for environmental fatigue evaluations if all evaluations are shown to be in compliance with fatigue acceptance criteria (i.e. U<1.0).

Implicit in this conclusion is the recognition that although these locations are not necessarily the highest in terms of fatigue, they are reasonably high to be representative since the associated fatigue analyses contain the conservatisms similar to those used for other locations. It is often necessary, as in the case of MNGP, to take credit for some of these conservatisms to comply with fatigue acceptance criteria.

In conclusion, if any environmental fatigue evaluation exceeds the acceptance criteria for the 60 year extended operating period consideration of other locations is required. For MNGP, all locations identified in NUREG/CR-6260 as representative for plants like MNGP have been evaluated and found to meet environmental fatigue acceptance criteria (see LRA Section 4.5). As a result, the current environmental fatigue evaluations which have been projected to the end of the license renewal term of operation (60 years), are adequate for plant representation without augmentation to other locations.

Audit Question No.: B2.1.15-01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Knox **MNGP Owner:** Ron Siepel **Discipline:** Electrical

Question: Describe how operating experience is captured.

Date Received: 6/14/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The site's Corrective Action Process (CAP) program identifies, tracks, and trends site operating experience related to all site components. Any site component which has been identified as being degraded, as having failed or as having a potential for not being able to fulfill its intended function is documented in the site CAP data base. These CAPs are then evaluated by plant engineering for extent of condition and appropriate follow up actions taken. Plant engineering also trends related CAPs to identify generic issues. Trended site issues are addressed in program health reports and presented to site management on a scheduled basis. The Corrective Action Process also addresses external operating events from INPO, LIS, NMC Fleet, NRC, and Part 21 issues.

Final Response: The site's Corrective Action Process (CAP) program identifies, tracks, and trends site operating experience related to all site components. Any site component which has been identified as being degraded, as having failed or as having a potential for not being able to fulfill its intended function is documented in the site CAP data base. These CAPs are then evaluated by plant engineering for extent of condition and appropriate follow up actions taken. Plant engineering also trends related CAPs to identify generic issues. Trended site issues are addressed in program health reports and presented to site management on a scheduled basis. The Corrective Action Process also addresses external operating events from INPO, LIS, NMC Fleet, NRC, and Part 21 issues.

Audit Question No.: B2.1.15-02

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Knox **MNGP Owner:** Ron Siepel **Discipline:** Electrical

Question: Provide the technical basis for the "sample" described in AMP-030. Is the sample based on the severity of adverse localized environment as compared to the plant design environment and other criteria such as accessibility, availability, importance-to-safety, or prior inspection results. The basis for selecting the sample is not clear. Provide clarification.

Date Received: 6/14/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program has not been written. The technical basis will be provided in the site program document. This program will consider the guidance provided by Contractor Report SAND96-0344 Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Terminations Section 6.3.3. This guidance provides for consideration of location (proximity to high-temperature equipment and radiation sources), environment (design vs. actual), ampacity (rated vs. design currents) and other criteria. The program will consider site operating experience and trend data, cables in systems important to safety and necessary for reliable operation, and cables in locations not normally accessible during normal plant operation, to ensure that a representative sample is evaluated.

Final Response: The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program has not been written. The technical basis will be provided in the site program document. This program will consider the guidance provided by Contractor Report SAND96-0344 Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Terminations Section 6.3.3. This guidance provides for consideration of location (proximity to high-temperature equipment and radiation sources), environment (design vs. actual), ampacity (rated vs. design currents) and other criteria. The program will consider site operating experience and trend data, cables in systems important to safety and necessary for reliable operation, and cables in locations not normally accessible during normal plant operation, to ensure that a representative sample is evaluated.

Audit Question No.: B2.1.6-01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Knox **MNGP Owner:** Ron Siepel **Discipline:** Electrical

Question: The parameters monitored or inspected program element of AMP B2.1.6 conveys that internal bus supports will be inspected for structural integrity and cracking. Define the location of the AMP where (internal) bus supports are inspected for structural integrity and cracking.

Date Received: 7/18/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Section B2.1.6 of Appendix B of the Monticello License Renewal Application under the paragraph titled "Parameters Monitored or Inspected" states "The bus supports will be inspected for structural integrity and cracking." This statement is consistent with proposed ISG-17. In this statement "bus supports" refers to the actual bus insulators and metal channels (to which the insulators are attached), which are located inside the Metal Enclosed Bus enclosure. The term "bus" refers to the actual copper bus bars which conduct electrical power. The overall "bus duct" or more appropriately "metal enclosed bus assembly" supports (those supports which are fabricated of structural steel and support the metal enclosed bus from the concrete foundation) are inspected under the Structures Monitoring Program. The new program basis document for the " Bus Duct Inspection Program" will clearly define the requirement to inspect the internal electrical bus and the internal bus supports (insulators and metal channel).

Final Response: Section B2.1.6 of Appendix B of the Monticello License Renewal Application under the paragraph titled "Parameters Monitored or Inspected" states "The bus supports will be inspected for structural integrity and cracking." This statement is consistent with proposed ISG-17. In this statement "bus supports" refers to the actual bus insulators and metal channels (to which the insulators are attached), which are located inside the Metal Enclosed Bus enclosure. The term "bus" refers to the actual copper bus bars which conduct electrical power. The overall "bus duct" or more appropriately "metal enclosed bus assembly" supports (those supports which are fabricated of structural steel and support the metal enclosed bus from the concrete foundation) are inspected under the Structures Monitoring Program. The new program basis document for the " Bus Duct Inspection Program" will clearly define the requirement to inspect the internal electrical bus and the internal bus supports (insulators and metal channel).

Audit Question No.: B2.1.6-02

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Knox **MNGP Owner:** Ron Siepel **Discipline:** Electrical

Question: Describe the extent of accessibility to the internal portions of bus duct.

Date Received: 7/18/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The metal enclosed bus is provided with a removable top cover. This cover is made up of sections and runs the entire length of the metal enclosed bus. On portions of the metal enclosed bus where it transitions from horizontal to vertical the top cover is oriented vertically and is still removable. Once the cover has been removed, all three phases of the bus are visible. The bus insulator supports, insulators, bus bar and connections are visible either unaided or aided with the use of an inspection mirror. The only portion of the bus enclosure in which complete removal of the top cover is not possible is that portion which passes through the turbine building wall penetration. The existing configuration allows for full inspection of the internal bus, insulation material, internal insulators, internal mounting channels and internal portions of the metal enclosure.

Final Response: The metal enclosed bus is provided with a removable top cover. This cover is made up of sections and runs the entire length of the metal enclosed bus. On portions of the metal enclosed bus where it transitions from horizontal to vertical the top cover is oriented vertically and is still removable. Once the cover has been removed, all three phases of the bus are visible. The bus insulator supports, insulators, bus bar and connections are visible either unaided or aided with the use of an inspection mirror. The only portion of the bus enclosure in which complete removal of the top cover is not possible is that portion which passes through the turbine building wall penetration. The existing configuration allows for full inspection of the internal bus, insulation material, internal insulators, internal mounting channels and internal portions of the metal enclosure.

Audit Question No.: B2.1.6-03

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Knox **MNGP Owner:** Ron Siepel **Discipline:** Electrical

Question: The detection of aging effects program element of AMP B2.1.6 conveys that an existing program - plant preventive maintenance procedures - will be revised to include license renewal requirements. However, the program description indicates that the program is a new program versus a partially new program and revised existing program. Provide clarification.

Date Received: 7/18/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Monticello Nuclear Generating Plant (MNGP) currently implements metal enclosed bus inspections using existing preventative maintenance (PM) procedures. These PMs perform routine inspections of transformers and associated metal enclosed bus. These PMs are not part of an established industry program (such as Fire Protection, EQ, MOV, etc.) , rather they are a preventative maintenance practice to ensure safe and reliable operation. As described in Appendix B of the Monticello License Renewal Application, MNGP is committing to a Metal Enclosed Bus Inspection Program. The Metal Enclosed Bus Inspection Program will be a new program which will be controlled by a program basis document that will contain the 10 elements as described in NUREG 1800. The implementation portion of the new program will use the existing PMs to document the requirements of 10 CFR 54. These PMs will be revised to reflect the MNGP Commitment Number, which will ensure that the PMs are not adversely changed in the future. The PMs will be revised to include the required inspection interval and other requirements of the new program.

Final Response: Monticello Nuclear Generating Plant (MNGP) currently implements metal enclosed bus inspections using existing preventative maintenance (PM) procedures. These PMs perform routine inspections of transformers and associated metal enclosed bus. These PMs are not part of an established industry program (such as Fire Protection, EQ, MOV, etc.) , rather they are a preventative maintenance practice to ensure safe and reliable operation. As described in Appendix B of the Monticello License Renewal Application, MNGP is committing to a Metal Enclosed Bus Inspection Program. The Metal Enclosed Bus Inspection Program will be a new program which will be controlled by a program basis document that will contain the 10 elements as described in NUREG 1800. The implementation portion of the new program will use the existing PMs to document the requirements of 10 CFR 54. These PMs will be revised to reflect the MNGP Commitment Number, which will ensure that the PMs are not adversely changed in the future. The PMs will be revised to include the required inspection interval and other requirements of the new program.

Audit Question No.: B2.1.6-04

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Knox **MNGP Owner:** Ron Siepel **Discipline:** Electrical

Question: The program element for detection of aging effects in AMP B2.1.6 indicates that an existing plant preventive maintenance procedure require some bus duct to be inspected. These inspections require the removal of all outside bus (duct covers and the inspection of the bus duct for water, foreign material, bus) support damage and loose connections. These procedures require a micro-ohm test and a power factor test once maintenance activities have been completed. Describe the operating experience results from these inspections and confirm that they are bounded by industry experience defined in the LRA.

Date Received: 7/18/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The current Preventative Maintenance (PM) procedures requires 1) Removal of bus duct covers 2) Clean/repair bus and bus duct as required and 3) QC inspection of the bus duct located outside the Turbine building for water and foreign material. The current and previous revisions to these procedures require the person performing the action to initial the step once it has been performed. There are no current or previous requirements to document the results of the inspection other than to initial the step. As required by 10 CFR 50 Appendix B, any conditions adverse to quality would be identified and documented in the corrective action process. There were no corrective action reports for MNGP which identified any condition adverse to quality. From a review of previously completed PM procedures, the last metal enclosed bus inspection of the bus connected to the 2R transformer was performed in June 2003. The last metal enclosed bus inspection of the bus connected to the 1R transformer was performed in September 2000. A review of various power factor tests performed since 1994 did not indicate any insulation degradation. The requirement for micro-ohm testing was added to the PMs prior to 2003. Micro-ohm test results for the metal enclosed bus connected to the 2R transformer, performed during June 2003, and micro-ohm test results for the metal enclosed bus connected to the 1R transformer, performed during April 2004, did not indicate abnormal values.
From MNGP LRA Appendix B2.1.6 "Industry operating experience has demonstrated that the failures of bus ducts are caused by cracked insulation of the bus combined with moisture or debris buildup internal to the bus ducts. It has also been shown that bus duct internals exposed to appreciable ohmic heating during operation may experience loosening of bolted connections related to repeated cycling of connected loads."
The metal enclosed bus visual inspections, power factor and micro-ohm testing currently performed at MNGP are capable of detecting the failures as described in industry operating experience. The visual inspection will detect any cracked or discolored insulation, cracked or structural integrity issues with the insulators, moisture intrusion or debris buildup internal to the bus. The power factor testing provides indication of insulation degradation. Micro-ohm testing provides indication of high impedance in bolted connections.

Final Response: The current Preventative Maintenance (PM) procedures requires 1) Removal of bus duct covers 2) Clean/repair bus and bus duct as required and 3) QC inspection of the bus duct located outside the Turbine building for water and foreign material. The current and previous revisions to these procedures require the person performing the action to initial the step once it has been performed. There are no current or previous requirements to document the results of the inspection other than to initial the step. As required by 10 CFR 50 Appendix B, any conditions adverse to quality would be identified and documented in the corrective action process. There were no corrective action reports for MNGP which identified any condition adverse to quality. From a review of previously completed PM procedures, the last metal enclosed bus inspection of the bus connected to the 2R transformer was performed in June 2003. The last metal enclosed bus inspection of the bus connected to the 1R transformer was performed in September 2000. A review of various power factor tests performed since 1994 did not indicate any insulation degradation. The requirement for micro-ohm testing was added to the PMs prior to 2003. Micro-ohm test results for the metal enclosed bus connected to the 2R transformer, performed during June 2003, and micro-ohm test results for the metal enclosed bus connected to the 1R transformer, performed during April 2004, did not indicate abnormal values.
From MNGP LRA Appendix B2.1.6 "Industry operating experience has demonstrated that the failures of bus ducts are caused by cracked insulation of the bus combined with moisture or debris buildup internal to the bus ducts. It has also been shown that bus duct internals exposed to appreciable ohmic heating during operation may experience loosening of bolted connections related to repeated cycling of connected loads."
The metal enclosed bus visual inspections, power factor and micro-ohm testing currently performed at MNGP are capable of detecting the failures as described in industry operating experience. The visual inspection will detect any cracked or discolored insulation, cracked or structural integrity issues with the insulators, moisture intrusion or debris buildup internal to the metal enclosure. The power factor testing provides indication of insulation degradation. Micro-ohm testing provides indication of high impedance in bolted connections.

Audit Question No.: B2.1.6-05

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Knox **MNGP Owner:** Ron Siepel **Discipline:** Electrical

Question: The proposed USAR Supplemental information included in Section A2.1.6 of the LRA (or by letter dated June 10, 2005) does not provide a summary description of the frequency of inspection similar to that described in the detection of aging effects program element for MNGP AMP B2.1.6. Provide justification for its omission or provide a revised USAR supplement which includes the frequency of inspection.

Date Received: 7/18/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Revised Appendix A2.1.6 makes the commitment as follows: "Prior to the period of extended operation, the Bus Duct Inspection Program will be implemented consistent with the appropriate ten elements described in Appendix A of NUREG-1800, Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants."

As described in LRA Section B2.1.6 Program Element 4 DETECTION OF AGING EFFECTS
"Visual inspection of internal portions of bus ducts detects cracks, corrosion, debris, dust and moisture. Visual inspection of the bus insulating system detects embrittlement, cracking, melting, swelling and discoloration. Visual inspection of bus supports detects cracking and lack of structural integrity. Internal portions of bus ducts, the bus insulating system, and the bus supports are visually inspected at least once every 10 years. A torque test or a resistance test of a sample of accessible bolted connections is performed at least once every 10 years. This program will be completed before the end of the initial 40-year license term and every 10 years thereafter. This is an adequate period to preclude failures of the bus ducts since experience has shown that aging degradation is a slow process. A 10-year inspection frequency will provide two data points during a 20-year period, which can be used to characterize the degradation rate."
As stated in Appendix A2.1.6, MNGP is committing to the ten elements as described in Appendix A of NUREG-1800, Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants. The specific inspection frequency time period is described in LRA Section B2.1.6.

Final Response: Revised Appendix A2.1.6 makes the commitment as follows: "Prior to the period of extended operation, the Bus Duct Inspection Program will be implemented consistent with the appropriate ten elements described in Appendix A of NUREG-1800, Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants."

As described in LRA Section B2.1.6 Program Element 4 DETECTION OF AGING EFFECTS
"Visual inspection of internal portions of bus ducts detects cracks, corrosion, debris, dust and moisture. Visual inspection of the bus insulating system detects embrittlement, cracking, melting, swelling and discoloration. Visual inspection of bus supports detects cracking and lack of structural integrity. Internal portions of bus ducts, the bus insulating system, and the bus supports are visually inspected at least once every 10 years. A torque test or a resistance test of a sample of accessible bolted connections is performed at least once every 10 years. This program will be completed before the end of the initial 40-year license term and every 10 years thereafter. This is an adequate period to preclude failures of the bus ducts since experience has shown that aging degradation is a slow process. A 10-year inspection frequency will provide two data points during a 20-year period, which can be used to characterize the degradation rate."
As stated in Appendix A2.1.6, MNGP is committing to the ten elements as described in Appendix A of NUREG-1800, Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants. The specific inspection frequency time period is described in LRA Section B2.1.6.

Audit Question No.: B3.1-01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Knox **MNGP Owner:** Ron Siepel **Discipline:** Electrical

Question: 1. Give some examples of the ways that MNGP identifies EQ specific OE? Give some examples of MNGP's Industry interface?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Answer: The Corrective Action Process (CAP) addresses XOEs from INPO, LIS, NMC Fleet and Part 21 issues. Additionally, the CAP program trends site issues which are then addressed in the program health reports.

Answer: Peer evaluations, NMC fleet meetings, Industry meetings (NUGEQ Annual Meeting), Scientech EQDB Newsletters, NUGEQ periodic OE Memo of Industry Information, Use of outside contractors which have extensive industry experience, Benchmarking of recently audited sites (Cooper), Focused Self Assessments utilizing outside experts.

Final Response: Answer: The Corrective Action Process (CAP) addresses XOEs from INPO, LIS, NMC Fleet and Part 21 issues. Additionally, the CAP program trends site issues which are then addressed in the program health reports.

Answer: Peer evaluations, NMC fleet meetings, Industry meetings (NUGEQ Annual Meeting), Scientech EQDB Newsletters, NUGEQ periodic OE Memo of Industry Information, Use of outside contractors which have extensive industry experience, Benchmarking of recently audited sites (Cooper), Focused Self Assessments utilizing outside experts.

Audit Question No.: B3.1-02

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Knox **MNGP Owner:** Ron Siepel **Discipline:** Electrical

Question: 2. Concerning aging effects during the extended period, how will you define/identify localized Harsh environments?

How will you account for radiation?

What procedures will you use to extend QLs?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Answer: Localized harsh environments are identified by plant walk downs, engineering evaluations performed during the corrective action process, temperature monitoring and thermography. Periodic radiation surveys are performed which identify changes to existing conditions. These changes are entered into the site CAP process and are evaluated for effects to individuals and equipment. Significant changes are incorporated into the EQ Program's radiation calculation and if required, into individual component calculations.

Answer: Radiation values over the period of extended operation are accounted for by increasing the calculated radiation values for the sixty year period. The revised radiation values are then incorporated into each individual components calculation file. Any deviation in existing radiation values are identified in the Corrective Action Program (CAP) process and an extent of condition evaluation performed.

Answer: Each individual components' calculation file will be updated to account for the increased radiation exposure, cycle times and temperature for the 60 year extended period in accordance with EWI-08.11.01 EQUIPMENT QUALIFICATION USER'S MANUAL, which uses NRC approved methodology.

Final Response: Answer: Localized harsh environments are identified by plant walk downs, engineering evaluations performed during the corrective action process, temperature monitoring and thermography. Periodic radiation surveys are performed which identify changes to existing conditions. These changes are entered into the site CAP process and are evaluated for effects to individuals and equipment. Significant changes are incorporated into the EQ Program's radiation calculation and if required, into individual component calculations.

Answer: Radiation values over the period of extended operation are accounted for by increasing the calculated radiation values for the sixty year period. The revised radiation values are then incorporated into each individual components calculation file. Any deviation in existing radiation values are identified in the Corrective Action Program (CAP) process and an extent of condition evaluation performed.

Answer: Each individual components' calculation file will be updated to account for the increased radiation exposure, cycle times and temperature for the 60 year extended period in accordance with site EQ program requirements, which uses NRC approved methodology.

Audit Question No.: B3.1-03

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Knox **MNGP Owner:** Ron Siepel **Discipline:** Electrical

Question: 3. What documents the answers to these questions?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The site documents which control these programs are: EWI-08.11.01 EQUIPMENT QUALIFICATION USER'S MANUAL which provides the guidance for maintaining the EQ Program; 4 AWI-10.01.08 Operating Experience Program; 4 AWI-10.01.03 Action Request Process. The actual answers to the questions can be documented in a formal RAI docketed response if the individual asking the question decides to make the question a formal RAI.

Final Response: The site documents which control these programs are: the site EQ program manual which provides the guidance for maintaining the EQ Program; the site administrative work instruction for operating experience; and the site administrative work instruction for the corrective action program. The actual answers to the questions can be documented in a formal RAI docketed response if the individual asking the question decides to make the question a formal RAI.

Audit Question No.: B2.1.17-01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lapp **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question: Under Exceptions, the Cable Spreading Room Halon System is inspected every 18 months versus the recommended 6 months in NUREG-1801, XI.M26. This is based on the CLB for the plant. Please give technical justification why the 18 month inspection frequency will be adequate during the period of extended operation as opposed to the NUREG-1801, XIM26 (Parameters Monitored/Inspected) 6 month guideline.

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The justification for the Cable Spreading Room Halon System being functionally tested and visually inspected every 18 months instead of the every six months as recommended in NUREG-1801, XI.M26 is that the surveillance interval specified in the Operations Manual is part of the NRC approved Fire Protection Program, thus forming an element of the plant's CLB. Although the surveillance interval is specified in the Operations Manual, it is historically traceable to the Technical Specifications, having resided there until removal under the guidelines of Generic Letters 86-10 and 88-12. This is also addressed in PBD/AMP-013, Fire Protection, Section 2.3. A review of surveillance test results and plant-specific operating experience for this subsystem has revealed no age related degradation and demonstrated that the 18-month frequency is acceptable.

JPP 6/13/05

Final Response: The justification for the Cable Spreading Room Halon System being functionally tested and visually inspected every 18 months instead of the every six months as recommended in NUREG-1801 (XI.M26) is that the surveillance interval specified in the Operations Manual is part of the NRC approved Fire Protection Program, thus forming an element of the plant's CLB. A review of industry operating experience, surveillance test results for this test and plant-specific operating experience for this subsystem has revealed no age related degradation and demonstrated that the 18-month frequency is acceptable.

Audit Question No.: B2.1.17-02

Source: **AMP Audit** **Status:** **Sufficient per NRC** **Author:** **Lapp** **MNGP Owner:** **Bill Roman** **Discipline:** **Mechanical**

Question: Under Parameters Monitored/Inspected the enhanced program generically describes visual inspections of items in scope for license renewal. Does the program have specific guidelines as to the percentage of components examined?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: See response to Draft RAI B2.1.17-03.

JPP 6/13/05

Final Response: See response to AMP Audit Question B2.1.17-03.

Audit Question No.: B2.1.17-03

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lapp **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question: Parameters Monitored/Inspected. Does the program have specific guidelines as to the frequency of the inspections?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The program does have specific guidelines as to the frequency of the inspections. These guidelines are addressed in Section 3.3, B of Program Basis Document PBD/AMP-013, Fire Protection, and are as follows:

Penetration Seals
Operations Manual B.08.05-05, "Fire Protection System Operation," Rev. 28, Table A.2.2, "Surveillance Requirements," requires:
Every 18 Months - Visual inspection of penetration fire barriers in fire area boundaries protecting safe shutdown equipment
Following Repair or Maintenance - Visual inspection of penetration seals

Penetration seals in all fire barriers protecting safe shutdown equipment, including internal 4KV bus duct seals, are visually inspected every 18 months for the following:
Penetrations with no seal
Visible light from the other side of the penetration seal
Air flowing through the penetration seal
Grouted pipe sleeves with no interior penetration seal
Penetration seals with large cracks or holes through to the thermal board
Insulation jacketing butting up against a sleeve or barrier that makes it difficult to tell whether a seal exists
Cables pulled away or out of thermal mastic or foam
Empty sleeves not capped or plugged
Thermal board mounting bolts loose or missing
A gap between the concrete and a ventilation or bus duct
A duct with no fire damper
Missing seals around hatch edges, when required
Any questionable appearance of a penetration seal

The MNGP Fire Protection Program meets the NUREG-1801 recommendation to inspect 10% of each type penetration seal. The examination criteria specified in MNGP procedures are consistent with the NUREG-1801 recommendation.

Fire Barriers
Operations Manual B.08.05-05, "Fire Protection System Operation," Table A.2.2, "Surveillance Requirements," requires:
Every 18 Months - Visual inspection of penetration fire barriers in fire area boundaries protecting safe shutdown equipment

A visual inspection is conducted every 18 months to verify the integrity and operability of plant fire barrier floors, walls, structural steel coating and dampers that separate redundant trains of safe shutdown systems.

Inspections of the barriers includes the following:
Inspect both sides of the wall, floor or ceiling unless stated otherwise
Inspect the entire area of the wall, floor or ceiling for any openings or damage that might deteriorate the fire rating
Inspect structural steel coating for cracking, looseness or damage

In addition, a structural inspection is conducted on five-year intervals, per the Maintenance Rule, via Procedure 1385, Periodic Structural Inspection. This procedure includes

an inspection of walls, floors and ceilings for the following, as a minimum:
Corrosion
Cracks
Deterioration
Discoloration
Honeycomb
Pitting
Pop out
Scaling
Palling
Water Infiltration
Missing or broken masonry blocks
Other conditions that may impact the capability of the structure to perform its intended function

Visual inspection of fire barrier walls to identify any abnormalities that have the potential to adversely affect the fire resistive capability of the assembly is consistent with the NUREG-1801 recommendation.

Fire Doors
Operations Manual B.08.05-05, "Fire Protection System Operation," Table A.2.2, "Surveillance Requirements," requires:
Every 18 Months - Visual inspection of penetration fire barriers in fire area boundaries protecting safe shutdown equipment

Fire doors are considered integral components of fire barriers. As such, they are inspected on the same frequency as fire barriers as specified in the Operations Manual. The 18-month surveillance interval for fire barriers (and associated components) specified in the Operations Manual is part of the NRC approved fire protection program, thus forming an element of the plant's licensing basis.

Although specified in the Operations Manual, the interval is historically traceable to the Technical Specifications, having resided there until removal under the guidelines of Generic Letters 86-10 and 88-12.
This requirement is implemented by the following procedures:

Procedure 1216-01, Fire Door Inspections
This procedure specifies daily and semiannual inspection criteria for fire doors in barriers that separate redundant safe shutdown trains as follows:
Daily Inspection
o Verify proper door position
o For doors not locked closed or electrically supervised, open door fully, verify proper knob rotation, verify door closes and latches
o Verify stationary side of double doors held in closed position

Semiannual Inspection
o Verify proper operation of automatic release mechanisms for held open doors

Procedure 0275-03, Fire Door Inspections
This procedure verifies frame to door clearance and latch throw operability requirements of fire doors located in fire barriers that separate redundant safe shutdown trains.

This procedure is performed every 18 months and requires the following inspections:
Verify doors have not been modified in any way that would reduce their effectiveness as rated fire doors such as:

o Door attachments other than door closers, intrusion alarm detectors and signs
o Check each door and frame for holes such as drill holes, screw or bolt holes and dents that go through a metal surface

o Verify each door not fastened shut closes completely when opened, that the door closer operates properly and the latch engages
o Verify that each side of the door (except for select doors) is not bowed
o Verify the minimum latch throw length is in accordance with the UL stamp
o Measure door to frame and door to sill gaps for acceptable clearances

Procedures that implement door inspection requirements confirm proper door operation, door integrity and gaps within acceptable limits.

Diesel-Driven Fire Pump
Operations Manual B.08.05-05, "Fire Protection System Operation," Table A.2.2, "Surveillance Requirements," requires:
Every Month - Start the pump from ambient conditions and run it for at least 20 minutes on recirculation flow
Every Three Months - Verify that a sample of fuel from the oil storage tank is within acceptable limits
Every 18 Months - Conduct a simulated automatic actuation including verification of pump capability

These requirements are implemented by the following procedures:

Procedure 1158-B, "Diesel Fire Pump Weekly Check"
This procedure calls for a weekly start of the diesel fire pump. The pump is run for at least 30 minutes with operating conditions monitored. An operator is required to observe engine parameters during the run.

Procedure 0261, "Fire Pump Exercise and Fuel Quantity Check"
This procedure requires starting the pump every month from ambient conditions and to run it for at least 30 minutes on recirculation flow. An operator is required to observe engine parameters during the run.

Procedure 0265, "Diesel Fire Pump Engine Inspection'
This procedure's purpose states in part:

Every 18 months, subject the diesel drive fire pump engine to an inspection in accordance with procedure prepared in conjunction with the manufacturer's recommendations for this class of standby service. Step one of Procedure 0265 requires the completion of Preventive Maintenance Procedure 4190-PM, "Diesel Engine, Fire Protection Pump." This procedure directs the preventive maintenance of the diesel engine fuel system, including the replacement of the main fuel filter.

Procedure 0266, "Fire Pumps Simulated Auto-Actuation and Capability Test"
This procedure calls for an annual test of the fire pumps, including the diesel fire pump. It verifies the ability of the pump to deliver required flow at the required pressure. An operator is required to observe engine parameters during the run.

Observation of engine parameters during pump run surveillance testing is consistent with the NUREG-1801 recommendation. The tests confirm the ability of the diesel-driven fire pump to meet performance requirements. Fuel supply line degradation manifesting itself in pump performance reduction would be detected by the testing.

Halon/Carbon Dioxide Systems / Cable Spreading Room Halon System
Operations Manual B.08.05-05, "Fire Protection System Operation" Table A.2.2, "Surveillance Requirements," requires:
Every 18 Months - Visually examine headers and nozzles and perform an airflow test upon evidence of obstructions of any halon system nozzle.
Every Three Years - Perform an airflow test through headers and nozzles to assure no blockage.

These requirements are implemented by the following procedure:

Procedure 0328, "Cable Spreading Room Halon System"
The system functional test and visual inspection is performed on a greater interval than recommended. The following justifies the difference between the NUREG-1801 recommendation and the MNGP program:

NUREG: Every six months, perform a visual inspection and function test MNGP; Every 18 months, visually examine headers and nozzles. Perform an airflow test upon evidence of obstruction of any nozzle. Functionally test the system. See response to Draft RAI B2.1.17-01.

JPP 6/13/05

Final Response: The program does have specific guidelines as to the frequency of the inspections. These guidelines are addressed in Fire Protection aging management program basis document, and are as follows:

Penetration Seals
Plant procedures specify surveillance requirements for penetration seals and require:
Every 18 Months - Visual inspection of penetration fire barriers in fire area boundaries protecting safe shutdown equipment
Following Repair or Maintenance - Visual inspection of penetration seals

Penetration seals in all fire barriers protecting safe shutdown equipment, including internal 4KV bus duct seals, are visually inspected every 18 months for the following:
Penetrations with no seal
Visible light from the other side of the penetration seal
Air flowing through the penetration seal
Grouted pipe sleeves with no interior penetration seal
Penetration seals with large cracks or holes through to the thermal board
Insulation jacketing butting up against a sleeve or barrier that makes it difficult to tell whether a seal exists
Cables pulled away or out of thermal mastic or foam
Empty sleeves not capped or plugged
Thermal board mounting bolts loose or missing
A gap between the concrete and a ventilation or bus duct
A duct with no fire damper
Missing seals around hatch edges, when required
Any questionable appearance of a penetration seal

The MNGP Fire Protection Program meets the NUREG-1801 recommendation to inspect 10% of each type penetration seal. The examination criteria specified in MNGP procedures are consistent with the NUREG-1801 recommendation.

Fire Barriers
Plant procedures specify surveillance requirements for fire barriers and require:
Every 18 Months - Visual inspection of penetration fire barriers in fire area boundaries protecting safe shutdown equipment

A visual inspection is conducted every 18 months to verify the integrity and operability of plant fire barrier floors, walls, structural steel coating and dampers that separate redundant trains of safe shutdown systems.

Inspections of the barriers includes the following:
Inspect both sides of the wall, floor or ceiling unless stated otherwise
Inspect the entire area of the wall, floor or ceiling for any openings or damage that might deteriorate the fire rating
Inspect structural steel coating for cracking, looseness or damage

In addition, a structural inspection is conducted on five-year intervals, per the Maintenance Rule, via procedure. This procedure includes an inspection of walls, floors and ceilings for the following, as a minimum:
Corrosion

Cracks
Deterioration
Discoloration
Honeycomb
Pitting
Pop out
Scaling
Palling
Water Infiltration
Missing or broken masonry blocks
Other conditions that may impact the capability of the structure to perform its intended function

Visual inspection of fire barrier walls to identify any abnormalities that have the potential to adversely affect the fire resistive capability of the assembly is consistent with the NUREG-1801 recommendation.

Fire Doors
Plant procedures specify surveillance requirements for fire doors and require:
Every 18 Months - Visual inspection of penetration fire barriers in fire area boundaries protecting safe shutdown equipment

Fire doors are considered integral components of fire barriers. As such, they are inspected on the same frequency as fire barriers as specified in the plant procedures. The 18-month surveillance interval for fire barriers (and associated components) specified in the plant procedure is part of the NRC approved fire protection program, thus forming an element of the plant's licensing basis.

Although specified in the plant procedure, the interval is historically traceable to the Technical Specifications, having resided there until removal under the guidelines of Generic Letters 86-10 and 88-12.
This requirement is implemented by the plant procedures:

Fire Door Inspections
The plant procedures concerning fire door inspection specifies daily and semiannual inspection criteria for fire doors in barriers that separate redundant safe shutdown trains as follows:
Daily Inspection
o Verify proper door position
o For doors not locked closed or electrically supervised, open door fully, verify proper knob rotation, verify door closes and latches
o Verify stationary side of double doors held in closed position

Semiannual Inspection
o Verify proper operation of automatic release mechanisms for held open doors

The plant procedures concerning fire door inspection also verify frame to door clearance and latch throw operability requirements of fire doors located in fire barriers that separate redundant safe shutdown trains.

This activity is performed every 18 months and requires the following inspections:
Verify doors have not been modified in any way that would reduce their effectiveness as rated fire doors such as:

o Door attachments other than door closers, intrusion alarm detectors and signs
o Check each door and frame for holes such as drill holes, screw or bolt holes and dents that go through a metal surface
o Verify each door not fastened shut closes completely when opened, that the door closer operates properly and the latch engages

o Verify that each side of the door (except for select doors) is not bowed
o Verify the minimum latch throw length is in accordance with the UL stamp
o Measure door to frame and door to sill gaps for acceptable clearances

Procedures that implement door inspection requirements confirm proper door operation, door integrity and gaps within acceptable limits.

Diesel-Driven Fire Pump
Plant procedures specify surveillance requirements for the Diesel-Driven Fire Pump and require:
Every Month - Start the pump from ambient conditions and run it for at least 20 minutes on recirculation flow
Every Three Months - Verify that a sample of fuel from the oil storage tank is within acceptable limits
Every 18 Months - Conduct a simulated automatic actuation including verification of pump capability

These requirements are implemented by the plant procedures and are summarized below:

The diesel fire pump weekly check procedure calls for a weekly start of the diesel fire pump. The pump is run for at least 30 minutes with operating conditions monitored. An operator is required to observe engine parameters during the run.

The fire pump exercise and fuel quantity check procedure requires starting the pump every month from ambient conditions and to run it for at least 30 minutes on recirculation flow. An operator is required to observe engine parameters during the run.

The diesel fire pump engine inspection procedure's purpose states in part:

Every 18 months, subject the diesel drive fire pump engine to an inspection in accordance with procedure prepared in conjunction with the manufacturer's recommendations for this class of standby service. The procedure requires the completion of preventive maintenance activities which includes preventive maintenance of the diesel engine fuel system, including the replacement of the main fuel filter.

The fire pumps simulated auto-actuation and capability test procedure calls for an annual test of the fire pumps, including the diesel fire pump. It verifies the ability of the pump to deliver required flow at the required pressure. An operator is required to observe engine parameters during the run.

Observation of engine parameters during pump run surveillance testing is consistent with the NUREG-1801 recommendation. The tests confirm the ability of the diesel-driven fire pump to meet performance requirements. Fuel supply line degradation manifesting itself in pump performance reduction would be detected by the testing.

Halon/Carbon Dioxide Systems / Cable Spreading Room Halon System
Plant procedures specify surveillance requirements for the Halon/Carbon Dioxide Systems / Cable Spreading Room Halon System and require:
Every 18 Months - Visually examine headers and nozzles and perform an airflow test upon evidence of obstructions of any halon system nozzle.
Every Three Years - Perform an airflow test through headers and nozzles to assure no blockage.

These requirements are implemented by the following procedure:

The plant procedure for the cable spreading room halon system functional test and visual inspection is performed on a greater interval than recommended. The following justifies the difference between the NUREG-1801 recommendation and the MNGP program:

NUREG: Every six months, perform a visual inspection and function test MNGP; Every 18 months, visually examine headers and nozzles. Perform an airflow test upon evidence of obstruction of any nozzle. Functionally test the system. See response to AMP audit question B2.1.17-01 for justification concerning this departure from the NUREG-1801 recommendation.

Audit Question No.: B2.1.17-04

Source: **AMP Audit** **Status:** **Sufficient per NRC** **Author:** **Lapp** **MNGP Owner:** **Bill Roman** **Discipline:** **Mechanical**

Question: Acceptance Criteria mentions that programs have specific acceptance criteria as appropriate for components under this program. This comment is very general, what are the specific acceptance criteria? Request to see the acceptance criteria of the program for the components listed.

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: See response to Draft RAI B2.1.17-03.

JPP 6/13/05

Final Response: See response to AMP audit question 2.1.17-03.

Audit Question No.: B2.1.17-05

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lapp **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question: Operating Experience noted that the Fire protection Program has been effective in managing aging and that the overall material condition is "good." Good is a very general term, good relative to what? Fair, poor excellent. Request to see some of the reports for the condition of components under the Fire Protection Program.

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The Operating Experience (OE) Program at MNGP assures that pertinent industry information regarding potential program impacts is disseminated for applicability evaluation and appropriate action. The OE Program is controlled by procedures FP-PA-OE-01, External Operating Experience (Reference 5.5.8), and 4 AWI-10.01.06, External Operating Experience (Reference 5.5.9). These procedures require screening of OE information, such as NRC Information Notices and Generic Letters, and entry of evaluation assignments into the corrective action program. Evaluation guidelines include an assessment of applicability to MNGP programs and design, potential vulnerability, and necessary corrective actions. With regard to items that potentially affect the Fire Protection Program, the OE item is forwarded to the program owner for evaluation and potential action that may include incorporating the issue into existing inspection or test procedures. Consequently, aging related issues are captured and evaluated within the corrective action system.

With regard to the specific penetration seal and fire door hinge issues that have been identified, the particular aging effects noted would be identified during routine inspections performed IAW the associated procedure. Other aging effects causing acceptance criteria not to be met would be captured within the corrective action program and incorporated into trending programs as appropriate.

Internally generated OE items are evaluated per the noted procedures to determine if industry notification is warranted. They are also captured within the MNGP corrective action program for trending consideration.

OE items and issues are programmatically controlled by established procedures to assure evaluations are conducted. OE items related to the MNGP Fire Protection Program are assessed through these established processes to determine if inspection and/or test procedures require revision. This process includes aging related items generated both externally and internally. As such, the MNGP program is consistent with the NUREG-1801 program element.

Additional Fire Protection Program related functions that may have a bearing on aging identification have taken place. These have been reviewed with regard to aging issues with the following results:

A self-assessment was performed in December 2000 utilizing NEI self-assessment guide 99-05, NEI Guidance for Fire Protection Self-Assessments, as the template. Within the self-assessment, the condition of penetration seals and structural steel fireproofing in the plant were visually observed. The conclusion of the assessment was that for those items inspected, the seals and fireproofing appeared in good condition. A recommendation was made to improve the inspection criteria for thermal fiber-backed mastic seals inside pipe sleeves to include cracks or holes in the thermal mastic layer through which the underlying thermal fiber material is visible. However, the term "good" is used frequently in describing system and/or component condition.

NRC Region III conducted a fire protection inspection in June 2002 (NRC Inspection Report 50-263/02-11). This inspection identified programmatic shortcomings associated with program implementation. These items ranged from items of non-compliance not entered into the corrective action system to lack of 10CFR50 Appendix R compliance with regard to physical separation of redundant safe shutdown functions. A review of the inspection report did not identify any aging related issues. Although none of the NRC identified items of concern were directly associated with the NUREG-1801 program elements, the lack of identification of program shortcomings within the corrective action system may be indirectly related, as aging issues may not have been documented.

As a result of the NRC inspection, a project team was assembled to recover the program and its control. In addition, Condition Report GEN 02005634 was issued. None of the associated action items are directly related to aging of fire protection system components. One project related item that may be construed to relate to the NUREG-1801 program elements was identification of the need to perform a NFPA code conformance review for fire doors (CR 03009083). However, this review is expected to be associated with door design, attachments and hardware as opposed to aging related issues.

A self-assessment was conducted in March 2004 (CR 04002449). The focus of the self-assessment was on program compliance with the corporate directive, progress in resolving NRC green findings, vulnerabilities related to triennial inspections, and comparison to NRC inspection criteria. No aging management concerns or issues were identified during this self-assessment.

Nuclear Oversight (Quality Assurance) observations and inspections (Annual, Biennial and Triennial) conducted from 1982 to 2003 were reviewed. No aging related items associated with the systems and commodities within the scope of this report were identified.

The System Health Report for the Fire Protection Program dated April 25, 2005 discusses these issues and shall be made available.

Final Response: The Operating Experience (OE) Program at MNGP assures that pertinent industry information regarding potential program impacts is disseminated for applicability evaluation and appropriate action. The OE Program is controlled by a fleet procedure implemented by a site procedure. These procedures require screening of OE information, such as NRC Information Notices and Generic Letters, and entry of evaluation assignments into the corrective action program. Evaluation guidelines include an assessment of applicability to MNGP programs and design, potential vulnerability, and necessary corrective actions. With regard to items that potentially affect the Fire Protection Program, the OE item is forwarded to the program owner for evaluation and potential action that may include incorporating the issue into existing inspection or test procedures. Consequently, aging related issues are captured and evaluated within the corrective action system.

With regard to the specific penetration seal and fire door hinge issues that have been identified, the particular aging effects noted would be identified during routine inspections performed IAW the associated procedure. Other aging effects causing acceptance criteria not to be met would be captured within the corrective action program and incorporated into trending programs, as appropriate.

Internally generated OE items are evaluated per the noted procedures to determine if industry notification is warranted. They are also captured within the MNGP corrective action program for trending consideration.

OE items and issues are programmatically controlled by established procedures to assure evaluations are conducted. OE items related to the MNGP Fire Protection Program are assessed through these established processes to determine if inspection and/or test procedures require revision. This process includes aging related items generated both externally and internally. As such, the MNGP program is consistent with the NUREG-1801 program element.

Additional Fire Protection Program related functions that may have a bearing on aging identification have taken place. These have been reviewed with regard to aging issues with the following results:

A self-assessment was performed in December 2000 utilizing NEI self-assessment guide 99-05, NEI Guidance for Fire Protection Self-Assessments, as the template. Within the self-assessment, the condition of penetration seals and structural steel fireproofing in the plant were visually observed. The conclusion of the assessment was that for those items inspected, the seals and fireproofing appeared in good condition. In other words, the seals and fireproofing were acceptable. A recommendation was made to improve the inspection criteria for thermal fiber-backed mastic seals inside pipe sleeves to include cracks or holes in the thermal mastic layer through which the underlying thermal fiber material is visible. NRC Region III conducted a fire protection inspection in June 2002 (NRC Inspection Report 50-263/02-11). This inspection identified programmatic shortcomings associated with program implementation. These items ranged from items of non-compliance not entered into the corrective action system to lack of 10CFR50 Appendix R compliance with regard to physical separation of redundant safe shutdown functions. A review of the inspection report did not identify any aging management related issues.

A self-assessment was conducted in March 2004. The focus of the self-assessment was on program compliance with the corporate directive, progress in resolving NRC green findings, vulnerabilities related to triennial inspections, and comparison to NRC inspection criteria. No aging management concerns or issues were identified during this self-assessment.

Nuclear Oversight (Quality Assurance) observations and inspections (Annual, Biennial and Triennial) conducted from 1982 to 2003 were reviewed. No aging related items associated with the systems and commodities within the scope of this report were identified.

The most recent 2005 system health report for the Fire Protection Program was discussed . Operating experience has confirmed that the Fire Protection Program has been effective in managing aging and that the overall material condition is acceptable.

Audit Question No.: B2.1.17-06

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lapp **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question: Operating Experience noted some areas of vulnerability. Request to see what portions of the Fire Protection System had vulnerability and the corrective actions taken.

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The term "vulnerability" was used in a generic sense regarding any issues that were identified and require correction or continued focus. See response to Draft RAI B2.1.17-05.

JPP 6/13/05

Final Response: The self-assessment conducted in March 2004 noted some areas of vulnerability in the Fire Protection Program. There were 4 objectives of the assessment consisting of the following: 1) Has MNGP established and is it implementing and maintaining a program consistent with the requirements of the NMC corporate directive for fire protection program standards. 2) What has been the progress of resolving the 6 green findings since the 2002 NRC Triennial Inspection. 3) What vulnerabilities does MNGP have to issues identified during other industry triennial inspections, and 4) How do MNGP Fire Protection and Appendix R Programs measure up to NRC current inspection criteria. The findings of this self-assessment were as follows.

1.MNGP has established and is implementing and maintaining a Fire Protection Program consistent with the requirements of NMC corporate directive for fire protection program standards. The gaps identified in the Gap analysis were evaluated in this assessment and adequate corrective actions are in place to resolve the Gaps and conform to the standard.
2.MNGP has made significant progress in resolving the six green 2002 Triennial Inspection findings. Corrective actions have been adequate and acceptable to the assessors. The corrective action of revising the plant procedure for fires outside of the control room was noted as a strength by the assessors.
3.The self-assessment team has identified issues from other triennial inspections and most have been addressed through the Safe Shutdown Analysis (SSDA). One particular issue was cited and entered into the Corrective Action Program as an External Operating Experience item. MNGP remains vulnerable to some issues identified in previous triennials because of the circuit analysis inspection moratorium and manual action feasibility. The circuit analysis inspection moratorium will be lifted before MNGP's next NRC Triennial Inspection. The new NRC circuit analysis methodology and manual action feasibility will be covered in the SSDA revision.
4.MNGP Fire Protection and Appendix R Programs are vulnerable to current NRC inspection criteria but progress through code evaluations and the Safe Shutdown Analysis update project will bring the programs up to industry standards.

The team identified the following Issues For Attention (IFA). The IFAs are: increasing the staff knowledge base, difficulty in retrieving documentation, Fire Brigade documentation is difficult to search and combustible loading control needs to be improved. The team's review also identified Enhancement Opportunities. One example is reviewing the Fire Strategies for references to toxic gases or other hazards. Each of the IFA and Enhancement Opportunities are discussed in detail within the remainder of the self-assessment report. Specific checklists with recommendations resulting from this assessment are attached included in the self-assessment report. A database was created to capture all of the questions asked during the self-assessment. The database printout is attached to the self-assessment report.

Corrective action documents were generated to track issues for attention identified during the self assessment

These areas of vulnerability concern issues related to the NRC's resolution of the circuit analysis inspection criteria, documentation, difficulties in retrieving and organizing information, staff turnover and limited knowledge base of the Fire Protection & Appendix R design and Licensing basis. The areas of vulnerability did not address any aging management related issues. A copy of this report is available for review. See also response to AMP audit question B2.1.17-05.

Audit Question No.: B2.1.18-01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lapp **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question: Enhancements to Detection of Aging Effects notes that program will be revised to include extrapolation of inspection results to below grade fire water piping with similar conditions that exist within the above grade fire water piping. Request to see how the program will perform this extrapolation and under what "similar conditions" this program would be implemented for the fire water piping.

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Fire protection system testing is performed to assure that the system functions by maintaining required operating pressures. Wall thickness evaluations of fire protection piping are performed on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion. These inspections are performed before the end of the current operating term and at plant specific intervals thereafter during the period of extended operation. As an alternative to non-intrusive testing, the plant maintenance process may include a visual inspection of the internal surface of the fire protection piping upon each entry to the system for routine or corrective maintenance, as long as it can be demonstrated that inspections are performed (based on past maintenance history) on a representative number of locations on a reasonable basis. These inspections must be capable of evaluating (1) wall thickness to ensure against catastrophic failure and (2) the inner diameter of the piping as it applies to the flow requirements of the fire protection system. If the environmental and material conditions that exist on the interior surface of the below grade fire protection piping are similar to the conditions that exist within the above grade fire protection piping, the results of the inspections of the above grade fire protection piping can be extrapolated to evaluate the condition of below grade fire protection piping. This only applies to the internal surfaces of fire water piping and is based on the rationale that the same material in the same environment under the same operating conditions would experience the same aging effects. If not, additional inspection activities are needed to ensure that the intended function of below grade fire protection piping will be maintained consistent with the current licensing basis for the period of extended operation. This would be based on sound engineering judgment and the criteria stated above.

Final Response: Fire protection system testing is performed to assure that the system functions by maintaining required operating pressures. Wall thickness evaluations of fire protection piping are performed on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion. These inspections are performed before the end of the current operating term and at plant specific intervals thereafter during the period of extended operation. As an alternative to non-intrusive testing, the plant maintenance process may include a visual inspection of the internal surface of the fire protection piping upon each entry to the system for routine or corrective maintenance, as long as it can be demonstrated that inspections are performed (based on past maintenance history) on a representative number of locations on a reasonable basis. These inspections must be capable of evaluating (1) wall thickness to ensure against catastrophic failure and (2) the inner diameter of the piping as it applies to the flow requirements of the fire protection system. If the environmental and material conditions that exist on the interior surface of the below grade fire protection piping are similar to the conditions that exist within the above grade fire protection piping, the results of the inspections of the above grade fire protection piping can be evaluated and utilized for the below grade fire protection piping. This only applies to the internal surfaces of fire water piping and is based on the rationale that the same material in the same environment under the same operating conditions would experience the same aging effects. If not, additional inspection activities are needed to ensure that the intended function of below grade fire protection piping will be maintained consistent with the current licensing basis for the period of extended operation. This would be based on sound engineering judgment and the criteria stated above. Operating experience at MNGP has indicated that these aging effects are the same.

Audit Question No.: B2.1.18-02

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lapp **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question: Under Scope of Program the aging management programs do not mention biofouling as a possible aging mechanism (NUREG-1801, XI.M27). Is biofouling not considered an aging mechanism for portions of the fire water system?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Biofouling is considered a potential aging mechanism for portions of the Fire Water System at MNGP and is addressed in Section B2.1.18, "Fire Water System Program Description" of the LRA (Page B-140) as follows:

The Fire Water System aging management program relies on testing of water based fire protection system piping and components in accordance with applicable NFPA recommendations. In addition, this program will be modified to include (1) portions of the fire protection sprinkler system that are subjected to full flow tests prior to the period of extended operation and (2) portions of the fire protection system exposed to water that are internally visually inspected. To ensure that the aging mechanisms of corrosion, and biofouling/fouling are properly being managed in the fire water system, periodic full flow flush test and system performance test are conducted. The system is also normally maintained at required operating pressure and is monitored such that loss of system pressure is immediately detected and corrective actions initiated.

Biofouling is further addressed in Section 3.4, Detection of Aging Effects of the Program Basis Document, PBD/AMP-014, "Fire Water System" as follows:

Biofouling inspections take place via the following procedures:

Procedure I.05.25, "Zebra Mussel Inspection,"
This procedure provides for the periodic inspection for the presence of zebra mussels. This is accomplished via visual inspection of a concrete block and the internal plates of a bio box placed in the plant intake bay.

Procedure 4057-PM, "Intake Bay/Traveling Screen Forebays Inspection,"
This procedure performs an annual visual inspection of the intake bay/traveling screen forebays for biofouling.

Procedure 4125-PM, "East Service Water Bay Inspection/Dredging,"
This procedure provides for the visual inspection of the East Service Water Bay. It is performed each refueling outage.

Procedure 4126-PM, "West Service Water Bay Inspection and Dredging,"
This procedure provides for the visual inspection of the West Service Water Bay. It is performed each refueling outage. Annual flow testing and flushing of mains and headers are performed to assure the system meets its intended design
function. Successful test results assure biofouling is not deteriorating system performance. Biocide treatments, when appropriate, assure measures are in place to preclude biofouling of the fire main system.

JPP 6/13/05

Final Response: Biofouling is considered a potential aging mechanism for portions of the Fire Water System at MNGP and is addressed in Section B2.1.18, "Fire Water System Program Description" of the LRA (Page B-140) as follows:

The Fire Water System aging management program relies on testing of water based fire protection system piping and components in accordance with applicable NFPA recommendations. In addition, this program will be modified to include (1) portions of the fire protection sprinkler system that are subjected to full flow tests prior to the period of extended operation and (2) portions of the fire protection system exposed to water that are internally visually inspected. To ensure that the aging mechanisms of corrosion, and biofouling/fouling are properly being managed in the fire water system, periodic full flow flush test and system performance test are conducted. The system is also

normally maintained at required operating pressure and is monitored such that loss of system pressure is immediately detected and corrective actions initiated.

Biofouling is further addressed in the MNGP Fire Water System aging management program basis document. Biofouling inspections are performed per plant procedures.

A plant procedure provides for the periodic inspection for the presence of zebra mussels. This is accomplished via visual inspection of a concrete block and the internal plates of a bio box placed in the plant intake bay.

A plant procedure performs an annual visual inspection of the intake bay/traveling screen forebays for biofouling.

A plant procedure provides for the visual inspection of the East Service Water Bay. It is performed each refueling outage.

A plant procedure provides for the visual inspection of the West Service Water Bay. It is performed each refueling outage.

Annual flow testing and flushing of mains and headers are performed to assure the system meets its intended design function.

Successful test results assure biofouling is not deteriorating system performance. Biocide treatments, when appropriate, assure measures are in place to preclude biofouling of the fire main system.

Audit Question No.: B2.1.18-03

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lapp **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question: Detection of Aging Effects states that testing and inspection will be done at regular intervals. What is the frequency of these inspections for the various components?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The frequency of the various tests and inspections vary as stated below:

Piping
Each fire pump discharge line is provided with a pressure indicator. Wet pipe sprinkler systems are equipped with flow switches that provide an alarm to the control room in the event of flow due to either leakage above a low flow value or system actuation. Low pressure in the system will result in sequential fire pump auto-starts that are alarmed in the control room. Local fire main pressure indication is provided in the Intake Structure and monitored by operators on a continual basis.

Operations Manual B.08.05-05, "Fire Protection System Operation," Table A.2.2, "Surveillance Requirements," requires:
Every 12 Months - Flush the Yard Main and the Reactor and Turbine Building headers
Every 12 Months - Cycle valves in flow paths supplying fire suppression water to safety-related structures, systems, and components
Every 18 Months - Perform a simulated automatic actuation of each fire pump and the screen wash/fire pump, including verification of pump capability
Every 3 Years - Perform system flow tests

The implementing procedures associated with the above requirements are summarized below.

Procedure 0266, "Fire Pumps Simulated Auto-Actuation and Capability Test,"
This test implements the 18-month requirement to demonstrate the automatic actuation capability of the pumps and the ability to deliver rated flow at rated pressure. The procedure also performs an annual flow test of each pump. A requirement to trend fire pump performance is included in the procedure.

Procedure 0267, "Fire Protection System Header Flush,"
This procedure implements the annual requirement to flush the Yard Main, Reactor Building header and Turbine Building header. It calls for flushing, via select yard hydrants. The evaluation of any debris collected is dispositioned by the System Engineer. After flushing is complete, biocide is injected into the yard mains via Procedure 1454, "Fire Protection Biocide Injection."

Procedure 0268, "Fire Protection System Flow Test,"
Although the Operations Manual requires the flow test every three years, this procedure is performed annually. This test measures flow and pressure in the yard main loop and the cooling tower loop. Biocide injection may take place during this test.

Procedure 1078-01/02/03, "Fire Protection Transformer and Building Siding Deluge Tests,"
This test initiates deluge onto the Main, 1R and 2R transformers and the Turbine Building west exterior wall siding. It is performed approximately once per cycle and determines if there is a reduction in flow to the transformers or building siding systems. A visual inspection of piping and sprinkler nozzle conditions is also performed.

Procedure FP-PE-SW-01, "Service Water and Fire Protection Inspection Program", establishes and implements requirements to perform periodic examinations to detect pipe wall thinning and internal blockage from silting and corrosion products. The objectives of the inspection program are to identify and determine the extent of potential piping degradation and to take appropriate action to maintain operability of fire protection water piping systems. Requirements for inspection of fire water system piping identified in the procedure include the following:
Visual inspection of disassembled piping components as repairs, replacements or general maintenance is performed.
Criteria for selection of examination locations

Periodic re-inspection or augmented inspection of piping reflecting degradation or blockage above established limits
Evaluation of pipe blockage or pipe wall thinning to assess operability and structural integrity of the piping system

Biofouling inspections take place via the following procedures:

Procedure I.05.25, "Zebra Mussel Inspection,"
This procedure provides for the periodic inspection for the presence of zebra mussels. This is accomplished via visual inspection of a concrete block and the internal plates of a bio box placed in the plant intake bay.

Procedure 4057-PM, "Intake Bay/Traveling Screen Forebays Inspection,"
This procedure performs an annual visual inspection of the intake bay/traveling screen forebays for biofouling.

Procedure 4125-PM, "East Service Water Bay Inspection/Dredging,"
This procedure provides for the visual inspection of the East Service Water Bay. It is performed each refueling outage.

Procedure 4126-PM, "West Service Water Bay Inspection and Dredging,"
This procedure provides for the visual inspection of the West Service Water Bay. It is performed each refueling outage. Annual flow testing and flushing of mains and headers are performed to assure the system meets its intended design
function. Successful test results assure biofouling is not deteriorating system performance. Biocide treatments, when appropriate, assure measures are in place to preclude biofouling of the fire main system. System pressure is monitored continuously. Sprinkler system flow switch actuation and sequential fire pump starting are two mechanisms by which potential leaks are detected. Also, testing is performed to assure system pressure can be maintained.

Inspections performed per Operations Manual-related surveillance procedures and the inspection program established by Procedure FP-PE-SW-01 address pipe degradation concerns identified in NUREG-1801. Inspections performed to detect biofouling potential of plant systems address the concerns identified in NUREG-1801. The testing and inspections discussed above will assure continued operability of the Fire Water System.

Implementing procedures will be revised for the following:
The results of the inspections of the above grade fire water piping will be extrapolated to evaluate the condition of below grade fire water piping, the environmental and material conditions that exist on the interior surface of the below grade fire water piping are similar to the conditions that exist within the above grade fire water piping.

Detection and Suppression Systems
Operability of detection and suppression systems is addressed through the surveillance requirements specified in Operations Manual B.08.05-05, "Fire Protection System Operation," Table A.2.2, "Surveillance Requirements," as
follows:

Every Month - Verify each valve (manual, power operated, or automatic) in the flow path that is not electrically supervised, locked, sealed or otherwise secured in position, is in its correct position
Every Six Months – Detection instrumentation and associated alarm circuitry in applicable zones shall be demonstrated operable via functional tests
Once Each Year - Cycle each testable valve in the flow path through at least one complete cycle of full travel
Every 18 Months - Perform a system functional test that includes, where applicable, simulated automatic actuation of the system and verification that the automatic valves in the flow path actuate to their correct positions on a test signal
At Least Once per 18 months - Perform a visual examination of system piping and sprinkler heads. Upon evidence of obstruction of any open head sprinkler, perform an airflow test
At Least Once per Five Years - Perform an air flow test through each open head sprinkler header and verify each open head is unobstructed

The following procedures implement the above requirements:

Procedure 0270, Fire Protection System Valve Position Verification,"
This procedure implements the monthly requirement to verify valve positions.

Procedure 0256, "Fire Detection Instrumentation Test,"
This procedure implements the six-month requirement to functionally test detection system instrumentation and alarm capability.

Procedure 1222, "Control Room Fire Detector Test,"
This procedure assures operability of Control Room detectors via a weekly test and annual battery replacement.

Procedure 0269, "Fire Protection Valve Check,"
This procedure implements the annual requirement to cycle valves.

Procedure 0324, "Fire Protection System – Sprinkler System Tests,"
This procedure performs the 18 month simulated functional test and visual examination of system piping, and sprinkler and deluge heads for those interior systems specified with operability requirements in the Operations Manual. It also implements the five-year airflow test, confirming no blockage in lines to open deluge heads by flowing air through the piping and checking for flow from each head.

Testing of detection and suppression systems as described above assure continued operability of these systems consistent with NUREG-1801 recommendations.

Hydrants
Operations Manual B.08.05-05, "Fire Protection System Operation," Table A.2.2, "Surveillance Requirements," requires:

Every Six Months (Spring and Fall) - Visually inspect each yard fire hydrant and verify the hydrant barrel is dry and the hydrant is not damaged
Every Year - Hydrostatically test each hose at a pressure at least 50 psig greater than the maximum available at any yard hydrant hose house and conduct an inspection of all gaskets in couplings

The above requirements are implemented by the following procedures:

Procedure 0319, "Fire Protection System / Yard Hydrant Barrel Inspection,"
This procedure implements the six-month hydrant barrel inspection including hydrant flushing

Procedure 0320, "Fire Hose Hydrostatic test / Exterior Hose Stations,"
This procedure implements the annual hydrostatic test and gasket inspection

The surveillances/inspections performed at MNGP are consistent with the NUREG-1801 recommendations.

Sprinkler Systems
As noted above (Detection and Suppression Systems), a visual examination of system piping and sprinkler heads is performed at least once per 18 months along with an airflow test of open heads at least once per five years.

Currently, sprinkler heads are not inspected before the end of the 50-year sprinkler head service life, or at 10-year intervals thereafter to ensure that signs of degradation, such as corrosion, are detected in a timely manner. Procedures will be developed to implement this enhancement prior to the period of extended operation.

Inspections performed per Operations Manual related surveillance procedures and the inspection program established by Procedure FP-PE-SW-01 address potential pipe degradation concerns identified in NUREG-1801, thereby assuring continued operability of sprinkler systems.

JPP 6/13/05

Final Response: The frequency of the various tests and inspections vary as stated below:

Piping
Each fire pump discharge line is provided with a pressure indicator. Wet pipe sprinkler systems are equipped with flow switches that provide an alarm to the control room in the event of flow due to either leakage above a low flow value or system actuation. Low pressure in the system will result in sequential fire pump auto-starts that are alarmed in the control room. Local fire main pressure indication is provided and monitored by operators on a continual basis.

Plant surveillances require:
Every 12 Months - Flush the Yard Main and the Reactor and Turbine Building headers
Every 12 Months - Cycle valves in flow paths supplying fire suppression water to safety-related structures, systems, and components
Every 18 Months - Perform a simulated automatic actuation of each fire pump and the screen wash/fire pump, including verification of pump capability
Every 3 Years - Perform system flow tests

The implementing procedures associated with the above requirements are summarized below.

Fire Pumps Simulated Auto-Actuation and Capability Test
A plant procedure implements the 18-month requirement to demonstrate the automatic actuation capability of the pumps and the ability to deliver rated flow at rated pressure. The procedure also performs an annual flow test of each pump. A requirement to trend fire pump performance is included in the procedure.

Fire Protection System Header Flush
A plant procedure implements the annual requirement to flush the Yard Main, Reactor Building header and Turbine Building header. It calls for flushing, via select yard hydrants. The evaluation of any debris collected is dispositioned by the System Engineer. After flushing is complete, biocide is injected into the yard mains via a plant procedure

Fire Protection System Flow Test
Although plant operations requires the flow test every three years, this procedure is performed annually. This test measures flow and pressure in the yard main loop and the cooling tower loop. Biocide injection may take place during this test.

Fire Protection Transformer and Building Siding Deluge Tests
A plant procedure initiates deluge onto the Main, 1R and 2R transformers and the Turbine Building west exterior wall siding. It is performed approximately once per cycle and determines if there is a reduction in flow to the transformers or building siding systems. A visual inspection of piping and sprinkler nozzle conditions is also performed.

A plant procedure establishes and implements requirements to perform periodic examinations to detect pipe wall thinning and internal blockage from silting and corrosion products. The objectives of the inspection program are to identify and determine the extent of potential piping degradation and to take appropriate action to maintain operability of fire protection water piping systems. Requirements for inspection of fire water system piping identified in the procedure include the following:

Visual inspection of disassembled piping components as repairs, replacements or general maintenance is performed.
Criteria for selection of examination locations
Periodic re-inspection or augmented inspection of piping reflecting degradation or blockage above established limits
Evaluation of pipe blockage or pipe wall thinning to assess operability and structural integrity of the piping system

Biofouling inspections take place via the following procedures:

Zebra Mussel Inspection
A plant procedure provides for the periodic inspection for the presence of zebra mussels. This is accomplished via visual inspection of a concrete block and the internal plates of a bio box placed in the plant intake bay.

Intake Bay/Traveling Screen Forebays Inspection
A plant procedure performs an annual visual inspection of the intake bay/traveling screen forebays for biofouling.

East Service Water Bay Inspection/Dredging
A plant procedure provides for the visual inspection of the East Service Water Bay. It is performed each refueling outage.

West Service Water Bay Inspection and Dredging
A plant procedure provides for the visual inspection of the West Service Water Bay. It is performed each refueling outage. Annual flow testing and flushing of mains and headers are performed to assure the system meets its intended design function. Successful test results assure biofouling is not deteriorating system performance. Biocide treatments, when appropriate, assure measures are in place to preclude biofouling of the fire main system. System pressure is monitored continuously. Sprinkler system flow switch actuation and sequential fire pump starting are two mechanisms by which potential leaks are detected. Also, testing is performed to assure system pressure can be maintained.

Inspections performed per operations-related surveillance procedures and the inspection program established by a plant procedure to address pipe degradation concerns identified in NUREG-1801. Inspections performed to detect biofouling potential of plant systems address the concerns identified in NUREG-1801. The testing and inspections discussed above will assure continued operability of the Fire Water System.

Implementing procedures will be revised for the following:
If the environmental and material conditions that exist on the interior surface of the below grade fire protection piping are similar to the conditions that exist within the above grade fire protection piping, the results of the inspections of the above grade fire protection piping can be evaluated and utilized for the below grade fire protection piping. This only applies to the internal surfaces of fire water piping and is based on the rationale that the same material in the same environment under the same operating conditions would experience the same aging effects. If not, additional inspection activities are needed to ensure that the intended function of below grade fire protection piping will be maintained consistent with the current licensing basis for the period of extended operation. This would be based on sound engineering judgment and the criteria stated above. Operating experience at MNGP has indicated that these aging effects are the same.

Detection and Suppression Systems
Operability of detection and suppression systems is addressed through the surveillance requirements specified in operating procedures as follows:

Every Month - Verify each valve (manual, power operated, or automatic) in the flow path that is not electrically supervised, locked, sealed or otherwise secured in position, is in its correct position
Every Six Months - Detection instrumentation and associated alarm circuitry in applicable zones shall be demonstrated operable via functional tests
Once Each Year - Cycle each testable valve in the flow path through at least one complete cycle of full travel
Every 18 Months - Perform a system functional test that includes, where applicable, simulated automatic actuation of the system and verification that the automatic valves in the flow path actuate to their correct positions on a test signal
At Least Once per 18 months - Perform a visual examination of system piping and sprinkler heads. Upon evidence of obstruction of any open head sprinkler, perform an airflow test
At Least Once per Five Years - Perform an air flow test through each open head sprinkler header and verify each open head is unobstructed

The following procedures implement the above requirements:

Fire Protection System Valve Position Verification
A plant procedure implements the monthly requirement to verify valve positions.

Fire Detection Instrumentation Test
A plant procedure implements the six-month requirement to functionally test detection system instrumentation and alarm capability.

Control Room Fire Detector Test

A plant procedure assures operability of Control Room detectors via a weekly test and annual battery replacement.

Fire Protection Valve Check
A plant procedure implements the annual requirement to cycle valves.

Fire Protection System & Sprinkler System Tests
A plant procedure performs the 18 month simulated functional test and visual examination of system piping, and sprinkler and deluge heads for those interior systems specified with operability requirements in the Operations Manual. It also implements the five-year airflow test, confirming no blockage in lines to open deluge heads by flowing air through the piping and checking for flow from each head.

Testing of detection and suppression systems as described above assure continued operability of these systems consistent with NUREG-1801 recommendations.

Hydrants
Operating procedure surveillances require:

Every Six Months (Spring and Fall) - Visually inspect each yard fire hydrant and verify the hydrant barrel is dry and the hydrant is not damaged
Every Year - Hydrostatically test each hose at a pressure at least 50 psig greater than the maximum available at any yard hydrant hose house and conduct an inspection of all gaskets in couplings

The above requirements are implemented by the following procedures:

Fire Protection System / Yard Hydrant Barrel Inspection
A plant procedure implements the six-month hydrant barrel inspection including hydrant flushing

Fire Hose Hydrostatic test / Exterior Hose Stations
A plant procedure implements the annual hydrostatic test and gasket inspection

The surveillances/inspections performed at MNGP are consistent with the NUREG-1801 recommendations.

Sprinkler Systems
As noted above (Detection and Suppression Systems), a visual examination of system piping and sprinkler heads is performed at least once per 18 months along with an airflow test of open heads at least once per five years.

Currently, sprinkler heads are not inspected before the end of the 50-year sprinkler head service life, or at 10-year intervals thereafter to ensure that signs of degradation, such as corrosion, are detected in a timely manner. Procedures will be developed to implement this enhancement prior to the period of extended operation.

Inspections performed per operations surveillance procedures and the inspection program established by plant procedure address potential pipe degradation concerns identified in NUREG-1801, thereby assuring continued operability of sprinkler systems.

Audit Question No.: B2.1.18-04

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lapp **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question: Detection of Aging Effects states that testing and inspections for various components will be accomplished. What type of testing and what kind of inspections will be performed (visual, etc.)?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: See response to Draft RAI B2.1.18-03.

JPP 6/13/05

Final Response: See response to AMP audit question B2.1.18-03.

Audit Question No.: B2.1.18-05

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lapp **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question: Operating Experience mentions that the program has been effective in managing aging effects due to corrosion and biofouling. Biofouling was not mentioned in the Scope of Program aging, this seems to be inconsistent. Request that applicant make this aging effect consistent in this Program.

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: See response to Draft RAI B2.1.18-02.

JPP 6/13/05

Final Response: See response to AMP audit question B2.1.18-02.

Audit Question No.: B2.1.25-01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lapp **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: Exception to NUREG-1801 states that the program will not monitor hydrogen peroxide, but rather site specific radiolysis modeling will be performed. (Based on EPRI TR-1008192). Request to evaluate the contents of EPRI TR-1008192 and the site specific program with Plant Chemistry Personnel.

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The MNGP LRA indicates site specific monitoring of hydrogen peroxide is not performed. As noted in Section 8.2.1.13 of EPRI TR-1008192, decomposition to water and oxygen can occur rapidly making reliable data difficult to obtain and concentrations can, instead, be estimated from radiolysis models. Monticello uses radiolysis models as the basis for establishing hydrogen injection rates to effectively reduce the level of oxidant in the reactor coolant and minimize the potential for stress corrosion cracking.

Initially, Monticello specific radiolysis models were prepared by the reactor vendor and used as the basis for Hydrogen Water Chemistry. Since then, a software computer program model has been developed as part of the BWR Vessel and Internals Project (BWRVIP) by EPRI that is now used by Monticello to perform radiolysis and electrochemical potential (ECP) calculations for specific regions inside the reactor vessel (BWR Vessel and Internals Application - BWRVIA). Results from this model are used as part of chemistry management and have been compared to prior reactor vendor model results to confirm appropriate application of the software modeling techniques to Monticello. The model is typically run at least twice each operating cycle, near the beginning and end of cycle, to account for changes in reactor flux and core flow on model results.

Final Response: The MNGP LRA indicates site specific monitoring of hydrogen peroxide is not performed. As noted in Section 8.2.1.13 of EPRI TR-1008192, decomposition to water and oxygen can occur rapidly making reliable data difficult to obtain and concentrations can, instead, be estimated from radiolysis models. Monticello uses radiolysis models as the basis for establishing hydrogen injection rates to effectively reduce the level of oxidant in the reactor coolant and minimize the potential for stress corrosion cracking.

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Audit Question No.: B2.1.25-02

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lapp **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: Exception to use BWRVIP-130 (EPRI TR-1008192) instead of BWRVIP-29 which it supersedes. Notes Peach Bottom SER (NUREG-1769, Accession Number ML030300673) found provisions of BWRVIP-79, 2000 revision acceptable because based on updated industry experience). Request to discuss the differences of the two programs with Plant Chemistry Personnel.

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The MNGP LRA notes the Plant Chemistry Program relies upon the 2004 Revision of the guidelines (EPRI TR-1008192, BWRVIP-130) and not BWRVIP-29 as specified in the GALL. The LRA further notes differences between earlier revisions and the 2000 revision of the water chemistry guidelines were previously found acceptable by the NRC because the 2000 Revision is based on updated industry experience. The MNGP LRA notes the 2004 Revision was similarly based on updated industry experience. Differences between the 2000 Revision and 2004 Revision (BWRVIP-130) were evaluated during preparation of the LRA. In response to this RAI, a similar comparison between BWRVIP-29 and the 2000 Revision was performed and the results are summarized below. The comparisons demonstrate that use of the 2004 Revision (BWRVIP-130) of the water chemistry guidelines provides acceptable guidance as it is based on updated industry experience.

In comparing BWRVIP-29 against the 2000 Revision of the water chemistry guidelines, the following key changes were noted:

The 2000 Revision of the BWR Water Chemistry Guidelines was issued in February 2000. The guidelines were revised to:
- Provide updated methodology for establishing site-specific BWR water chemistry control programs,
- Discuss the importance of good water chemistry in obtaining inspection relief,
- Reformat a portion of the report to be consistent with BWRVIP-62,
- Discuss other factors besides IGSCC that are influenced by water chemistry,
- Update and add industry median/average values for key parameters,
- Reduce the Action Level 1 limit for feedwater copper, strengthen the discussion on feedwater iron control, add diagnostic parameters for feedwater and reactor iron, update Flow Accelerated Corrosion (FAC) and fuel failure information, and adjust the feedwater dissolved oxygen limit to account for recent industry FAC data,
- Include separate tables for Hydrogen Water Chemistry (HWC) control and diagnostic parameters and relax some of the HWC plant chloride and sulfate limits,
- Reduce select chemistry surveillances where appropriate, and
- Add a discussion on the effect of impurity transients on crack growth rates.

Chemical parameters, frequency of measurement, Action Levels, and limits remain essentially unchanged except as follows:
- Insoluble iron was added as a diagnostic parameter for reactor water and feedwater - these additional parameters were adopted by Monticello,
- Higher Action Level 2 and 3 limits for chloride and sulfate for reactor water were added for plants with HWC or with HWC and noble metal chemical application (NMCA) - these higher limits were adopted by Monticello which is a HWC plant, however, far more restrictive (lower) limits remain in place for Action Level 1 and water chemistry optimization,
- Feedwater total copper limit was lowered for Action Level 1 - this more restrictive limit was adopted by Monticello,
- Feedwater and condensate dissolved oxygen limits were increased for Action Level 1 - these more restrictive limits were adopted by Monticello, and
- Demineralized water and condensate storage tank water conductivity, chloride, and sulfate sampling frequencies were increased to weekly - Monticello adopted weekly sampling. Monticello chemistry results and trends indicate weekly is a sufficient frequency.

In comparing the 2000 Revision against the 2004 Revision which is used by Monticello, the following key changes were noted:

The 2004 Revision of the BWR Water Chemistry Guidelines was issued in October 2004. The guidelines were revised to:
- Identify which portions of the document are mandatory, needed, or good practice considerations consistent with Nuclear Energy Institute (NEI) guidelines for the management of material issues,

- Update the technical basis for water chemistry control of Intergranular Stress Corrosion Cracking (IGSCC) using recent industry experience,
- Discuss the effects of Noble Metal Chemical Application (NMCA) and zinc injection on radiation fields using recent industry experience,
- Strengthen the discussion of corrosion-related fuel failures including control of zinc, iron, and copper levels,
- Address the possibility that IGSCC may be reduced with continued operation if the Action Levels are exceeded,
- Add recommended goals for optimizing water chemistry that balances conflicting requirements of materials, fuel, and radiation control,
- Relax recommended surveillance frequencies for some parameters to reduce operating cost without creating a significant adverse impact on plant chemistry,
- Update the discussion on BWR transient effects on IGSCC,
- Include methods for adjusting conductivity measurements based on the presence of ionic species, and
- Add a new appendix covering ultrasonic fuel cleaning.

Chemical parameters, frequency of measurement, Action Levels, and limits remain essentially unchanged except as follows:
- The Action Level definitions were clarified to provide additional guidance for addressing chemistry transients, including the establishment of an action time period for the most severe out of limit conditions (Action Level 3),
- For reactor water during startup/hot standby, dissolved oxygen and NMCA were moved from control to diagnostic parameters (limits and measurement frequencies remained unchanged). Also, insoluble iron was removed as a diagnostic parameter. However, it remains part of the suspended corrosion products monitoring of reactor feedwater/condensate prior to initiation of significant feedwater flow or at completion of cleanup.
- For reactor feedwater/condensate during startup/hot standby, suspended corrosion products was moved from control to diagnostic parameters. The limits and measurement frequency remain unchanged.
- Auxiliary water chemistry guidelines remain unchanged except for the addition of phosphate as a diagnostic parameter for Demineralized Water Storage Tanks (DWST) and Condensate Storage Tanks (CSTs) and the lowering of the conductivity limit for the spent fuel pool.

In summary, no significant changes to critical program elements have resulted in adopting the 2004 Revision of the water chemistry guidelines (BWRVIP-130). The technical basis and guidance have been updated at each revision to include additional industry experience.

Final Response: The MNGP LRA notes the Plant Chemistry Program relies upon the 2004 Revision of the guidelines (EPRI TR-1008192, BWRVIP-130) and not BWRVIP-29 as specified in the GALL. The LRA further notes differences between earlier revisions and the 2000 revision of the water chemistry guidelines were previously found acceptable by the NRC because the 2000 Revision is based on updated industry experience. The MNGP LRA notes the 2004 Revision was similarly based on updated industry experience. Differences between the 2000 Revision and 2004 Revision (BWRVIP-130) were evaluated during preparation of the LRA. In response to this RAI, a similar comparison between BWRVIP-29 and the 2000 Revision was performed and the results are summarized below. The comparisons demonstrate that use of the 2004 Revision (BWRVIP-130) of the water chemistry guidelines provides acceptable guidance as it is based on updated industry experience.

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- Discuss the importance of good water chemistry in obtaining inspection relief,
- Reformat a portion of the report to be consistent with BWRVIP-62,
- Discuss other factors besides IGSCC that are influenced by water chemistry,
- Update and add industry median/average values for key parameters,
- Reduce the Action Level 1 limit for feedwater copper, strengthen the discussion on feedwater iron control, add diagnostic parameters for feedwater and reactor iron, update Flow Accelerated Corrosion (FAC) and fuel failure information, and adjust the feedwater dissolved oxygen limit to account for recent industry FAC data,
- Include separate tables for Hydrogen Water Chemistry (HWC) control and diagnostic parameters and relax some of the HWC plant chloride and sulfate limits,
- Reduce select chemistry surveillances where appropriate, and
- Add a discussion on the effect of impurity transients on crack growth rates.

Chemical parameters, frequency of measurement, Action Levels, and limits remain essentially unchanged except as follows:

- Insoluble iron was added as a diagnostic parameter for reactor water and feedwater - these additional parameters were adopted by Monticello,
- Higher Action Level 2 and 3 limits for chloride and sulfate for reactor water were added for plants with HWC or with HWC and noble metal chemical application (NMCA) - these higher limits were adopted by Monticello which is a HWC plant, however, far more restrictive (lower) limits remain in place for Action Level 1 and water chemistry optimization,
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- Demineralized water and condensate storage tank water conductivity, chloride, and sulfate sampling frequencies were increased to weekly - Monticello adopted weekly sampling. Monticello chemistry results and trends indicate weekly is a sufficient frequency.

In comparing the 2000 Revision against the 2004 Revision which is used by Monticello, the following key changes were noted:

The 2004 Revision of the BWR Water Chemistry Guidelines was issued in October 2004. The guidelines were revised to:
- Identify which portions of the document are mandatory, needed, or good practice considerations consistent with Nuclear Energy Institute (NEI) guidelines for the management of material issues,
- Update the technical basis for water chemistry control of Intergranular Stress Corrosion Cracking (IGSCC) using recent industry experience,
- Discuss the effects of Noble Metal Chemical Application (NMCA) and zinc injection on radiation fields using recent industry experience,
- Strengthen the discussion of corrosion-related fuel failures including control of zinc, iron, and copper levels,
- Address the possibility that IGSCC may be reduced with continued operation if the Action Levels are exceeded,
- Add recommended goals for optimizing water chemistry that balances conflicting requirements of materials, fuel, and radiation control,
- Relax recommended surveillance frequencies for some parameters to reduce operating cost without creating a significant adverse impact on plant chemistry,
- Update the discussion on BWR transient effects on IGSCC,
- Include methods for adjusting conductivity measurements based on the presence of ionic species, and
- Add a new appendix covering ultrasonic fuel cleaning.

Chemical parameters, frequency of measurement, Action Levels, and limits remain essentially unchanged except as follows:
- The Action Level definitions were clarified to provide additional guidance for addressing chemistry transients, including the establishment of an action time period for the most severe out of limit conditions (Action Level 3),
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- For reactor feedwater/condensate during startup/hot standby, suspended corrosion products was moved from control to diagnostic parameters. The limits and measurement frequency remain unchanged.
- Auxiliary water chemistry guidelines remain unchanged except for the addition of phosphate as a diagnostic parameter for Demineralized Water Storage Tanks (DWST) and Condensate Storage Tanks (CSTs) and the lowering of the conductivity limit for the spent fuel pool.

In summary, no significant changes to critical program elements have resulted in adopting the 2004 Revision of the water chemistry guidelines (BWRVIP-130). The technical basis and guidance have been updated at each revision to include additional industry experience.

Audit Question No.: B2.1.25-03

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lapp **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: Under the Detection of Aging Effects the program uses a one time inspection for stagnant or low flow areas. Has the applicant identified these stagnant and low flow areas for the one time inspection?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: As noted in response to questions B2.1.23-01 and 02, six bins have been established for sample selection consistent with the objects for the One-Time Inspection Program. Two of these groups are specific to verifying the effectiveness of plant chemistry for cracking and loss of material (corrosion) aging effects. Subgroups have been established based on plant water source (e.g., suppression pool water, condensate storage tank water, etc.) to evaluate aging effects for each separate water source. A review of recent plant inspection results and work order history is in progress to identify specific sample locations. These results will be reviewed by a plant Expert Panel using personnel experienced in prior Monticello inspections. Some preliminary inspection locations have been identified, including low flow/stagnant areas, that will be reviewed by the Expert Panel.

Final Response: As noted in response to questions B2.1.23-01 and 02, six bins have been established for sample selection consistent with the objects for the One-Time Inspection Program. Two of these groups are specific to verifying the effectiveness of plant chemistry for cracking and loss of material (corrosion) aging effects. Subgroups have been established based on plant water source (e.g., suppression pool water, condensate storage tank water, etc.) to evaluate aging effects for each separate water source. A review of recent plant inspection results and work order history is in progress to identify specific sample locations. These results will be reviewed by a plant Expert Panel using personnel experienced in prior Monticello inspections. Some preliminary inspection locations have been identified, including low flow/stagnant areas, that will be reviewed by the Expert Panel.

Audit Question No.: B2.1.25-04

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lapp **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: Monitoring and Trending uses a Chemistry Performance Indicator (CPI) to monitor the effectiveness of the Chemistry Program. This CPI combines several key indicators. Request to discuss with Plant Chemistry Personnel the key indicators used in the CPI.

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The MNGP utilizes a number of performance indicators to monitor the effectiveness of plant chemistry. Many of these are available on the Monticello site LAN and accessible by station personnel. For example, top level indicators available on the site LAN that are updated on a monthly basis include:
- Reactor Water (conductivity, chloride, sulfate, soluble copper, and insoluble copper concentrations)
- Feedwater (iron, oxygen, zinc, hydrogen concentrations, and the number of hydrogen water chemistry reductions)
- Offgas (condenser air inleakage activity and pretreatment activity - both in microcuries per second)
- Effluents (stack activity and reactor building vent activity - both in microcuries per second)

Ranges and limits for all indicated values are based on administrative limits or water chemistry optimization (WCO) goals and more restrictive than corresponding 2004 water chemistry guideline Action Level 1 limits where defined by EPRI.

Additionally, a Chemistry Performance Indicator (CPI) is provided. The CPI is defined by INPO and includes reactor chlorides, sulfates, and feedwater total iron in a weighted calculation designed to provide a lowest (best) possible value of 1.0. The calculation is only performed if the daily average reactor power is greater than or equal to 10%. The indicators are displayed on a monthly basis and data is available for trending.

Final Response: The MNGP utilizes a number of performance indicators to monitor the effectiveness of plant chemistry. Many of these are available on the Monticello site LAN and accessible by station personnel. For example, top level indicators available on the site LAN that are updated on a monthly basis include:
- Reactor Water (conductivity, chloride, sulfate, soluble copper, and insoluble copper concentrations)
- Feedwater (iron, oxygen, zinc, hydrogen concentrations, and the number of hydrogen water chemistry reductions)
- Offgas (condenser air inleakage activity and pretreatment activity - both in microcuries per second)
- Effluents (stack activity and reactor building vent activity - both in microcuries per second)

Ranges and limits for all indicated values are based on administrative limits or water chemistry optimization (WCO) goals and more restrictive than corresponding 2004 water chemistry guideline Action Level 1 limits where defined by EPRI.

Additionally, a Chemistry Performance Indicator (CPI) is provided. The CPI is defined by INPO and includes reactor chlorides, sulfates, and feedwater total iron in a weighted calculation designed to provide a lowest (best) possible value of 1.0. The calculation is only performed if the daily average reactor power is greater than or equal to 10%. The indicators are displayed on a monthly basis and data is available for trending.

Audit Question No.: B2.1.25-05

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lapp **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: Operating Experience notes that several components susceptible to IGSCC where replaced (entire Recirculation System Piping, a number of safe ends connected to the reactor vessel, the jet pump hold down assembly and shroud head bolts). NUREG-1801, XI.M2 mentions in Operating Experience other components susceptible to IGSCC such as core shroud, access hole cover, top guide and core spray spargers. Did the applicant evaluate these other components for replacement?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The MNGP LRA includes a discussion of actions taken to address industry IGSCC issues in the Plant Chemistry Aging Management Program, including actions taken outside of the chemistry program to replace plant equipment with less susceptible materials. The intent of this additional discussion was not to present a complete list of equipment actions taken but to demonstrate, consistent with the GALL, that the plant routinely evaluates and addresses IGSCC concerns through both chemistry program actions and other actions. Aging management of stress corrosion cracking for the core shroud, access hole cover, top guide, core spray spargers, and other reactor vessel internals is addressed by the BWR Vessels Internal Aging Management Program (B2.1.12). Specific to the other components listed in this question, Yes, MNGP has performed evaluations as a result of NRC correspondence, industry experience, and plant inspection results. No replacement of these additional components have resulted from these evaluations but some modifications were performed and inspection requirements enhanced.

- The Core Shroud was evaluated in response to a number of industry and NRC issues, such as Generic Letter 94-03, IEIN 93-79, IEIN 97-17, and vendor information letters. The core shroud was inspected during the 1994 refueling outage and indications were found using ultrasonic and enhanced visual examination techniques. Dynamic analysis was performed assuming 360-degree through-wall cracks at the circumferential welds. The analysis concluded the shroud is structurally adequate to withstand all design basis events. This conclusion was reaffirmed as part of power rerate. During the 1996 outage several vertical welds were inspected and no significant indications were found. MNGP continues to participate in the BWRVIP for ongoing and future actions.
- The Core Spray Spargers were evaluated in response to IE Bulletin 80-13, plant internal inspection results, and vendor information letters. Increased inspection of the spargers was added to the MNGP In-Service Inspection Program. Additionally, MNGP installed mechanical clamps on both of the in-vessel tee box assemblies for the sparger loops during the 1994 refueling outage.
- The Top Guide was evaluated in response to IEIN 95-17 and vendor information letters. A visual inspection of 15 top guide cell locations were examined during the 1993 refueling outage, representing approximately 25% of the high fluence cells. No indications were found and no additional actions were identified. MNGP continues to participate in the BWRVIP for inspection requirements.
- The access hole covers were evaluated in response to vendor information letters. The MNGP In-Service Inspection Program was updated to include the inspection of access hole covers. No additional actions were identified based on inspection results of six other BWRs which revealed no indications of cracking. Further, the cover welds at MNGP are 2½" thick versus the 5/8" thick welds described in the vendor information letters.

Final Response: The MNGP LRA includes a discussion of actions taken to address industry IGSCC issues in the Plant Chemistry Aging Management Program, including actions taken outside of the chemistry program to replace plant equipment with less susceptible materials. The intent of this additional discussion was not to present a complete list of equipment actions taken but to demonstrate, consistent with the GALL, that the plant routinely evaluates and addresses IGSCC concerns through both chemistry program actions and other actions. Aging management of stress corrosion cracking for the core shroud, access hole cover, top guide, core spray spargers, and other reactor vessel internals is addressed by the BWR Vessels Internal Aging Management Program (B2.1.12). Specific to the other components listed in this question, Yes, MNGP has performed evaluations as a result of NRC correspondence, industry experience, and plant inspection results. No replacement of these additional components have resulted from these evaluations but some modifications were performed and inspection requirements enhanced.

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- The access hole covers were evaluated in response to vendor information letters. The MNGP In-Service Inspection Program was updated to include the inspection of access hole covers. No additional actions were identified based on inspection results of six other BWRs which revealed no indications of cracking. Further, the cover welds at MNGP are 2½" thick versus the 5/8" thick welds described in the vendor information letters.

Audit Question No.: B2.1.5-01

Source: **AMP Audit** **Status:** **Sufficient per NRC** **Author:** **Lapp** **MNGP Owner:** **Ray Dennis** **Discipline:** **Civil**

Question: Q1 - Under Enhancements, the Program will be enhanced to include buried components when uncovered. Is this an opportunistic inspection and/or part of the 10-year buried pipe inspection frequency?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The enhancement to the program is to capture inspection opportunities when buried components are uncovered at times other than during the scheduled buried piping inspection. Appropriate implementing procedure(s) will be updated, i.e. the excavating procedure, to ensure that when buried components are uncovered, an inspection is performed.

Final Response: The enhancement to the program is to capture inspection opportunities when buried components are uncovered at times other than during the scheduled buried piping inspection. Appropriate implementing procedure(s) will be updated, i.e. the excavating procedure, to ensure that when buried components are uncovered, an inspection is performed.

Audit Question No.: B2.1.5-02

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lapp **MNGP Owner:** Ray Dennis **Discipline:** Civil

Question: Q2 - How is the sampling of buried components (pipe, etc.) determined for the inspections mentioned in this enhanced program? Is this mostly based on operating experience with previous maintenance?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: In response to a commitment made to the MNGP Safety Audit Committee, an inspection procedure to inspect a section of buried piping near the off-gas stack was created. The program will be enhanced to include a review of buried components OE to determine if inspections in other areas are warranted.

OE has not identified any locations that are more susceptible to corrosion than any other. The only failures of buried components were on the well water piping system and the instrument air system to the cooling towers. The well water piping failure was postulated to be due to MIC and not a failure of the protective coating. The area of concern of the air line could not be excavated. Therefore, a nearby segment of the air line was excavated and inspected. This section showed no age related degradation. It was concluded that the line failure was not due to age related degradation, but some other mechanism. It should be noted that the air line is not safety related and the line has since been capped and abandoned in place.

Final Response: In response to a commitment made to the MNGP Safety Audit Committee, an inspection procedure to inspect a section of buried piping near the off-gas stack was created. The program will be enhanced to include a review of buried components OE to determine if inspections in other areas are warranted.

OE has not identified any locations that are more susceptible to corrosion than any other. The only failures of buried components were on the well water piping system and the instrument air system to the cooling towers. The well water piping failure was postulated to be due to MIC and not a failure of the protective coating. The area of concern of the air line could not be excavated. Therefore, a nearby segment of the air line was excavated and inspected. This section showed no age related degradation. It was concluded that the line failure was not due to age related degradation, but some other mechanism. It should be noted that the air line is not safety related and the line has since been capped and abandoned in place.

Audit Question No.: B2.1.5-03

Source: **AMP Audit** **Status:** **Sufficient per NRC** **Author:** **Lapp** **MNGP Owner:** **Ray Dennis** **Discipline:** **Civil**

Question: Q3 - Under Detection of Aging Effects there is a discussion of "mild soil conditions" at the site. Please provide technical evidence for concluding that there are "mild soil conditions."

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The basis for the determination of mild soil conditions at MNGP is discussed in Technical Report TR-012, Section 3.2.4. The following test results demonstrate that water chemistries for groundwater, well water, and river water are well within acceptable ranges.
USAR Section 2.4.5, Surface Water Quality, provides water samples taken upstream, downstream and at the plant discharge on February 28, 1972. The chemical analyses of the samples were as follows:

Sample Description	Mississippi (Upstream)	Mississippi (Downstream)	Plant Discharge
pH	7.5	7.9	7.8
Chloride (Cl)	1.4 ppm	0.9 ppm	1.0 ppm
Sulfate (SO4)	7.8 ppm	6.6 ppm	7.3 ppm

Groundwater samples taken at MNGP between 1984 and 1991:

Sample Description	Groundwater (1984 - 1991)
pH	7.5 to 8.0
Chloride (Cl)	0.5 to 1.5 ppm
Sulfate (SO4)	6 to 9 ppm

Groundwater samples taken at MNGP in February 2004:
Samples taken at domestic well 11, and monitoring wells 1, 2, and 3.

Sample Description	Domestic well 11	Monitoring well 1	Monitoring well 2	Monitoring well 3
pH	8.02	7.59	7.48	7.43
Chloride (Cl)	72 mg/L	7 mg/L	29 mg/L	19 mg/L
Sulfate (SO4)	12 mg/L	9 mg/L	22 mg/L	13 mg/L

Well water samples taken at MNGP between 1984 and 1991:
Note: Wells 1 and 2 are located 1000 (+) feet southwest of the power block and are over 85 feet deep.

Sample Description	Well Water (1984 - 1991)
pH	7.7 to 7.9
Chloride (Cl)	15.9 to 17.9 ppm
Sulfate (SO4)	38.6 to 58.5 ppm

Water samples taken at MNGP on 6-30-2003:

Sample Description	Circulating Water (6-30-03)
pH	8.3
Chloride (Cl)	10.8 ppm

Sulfate (SO4) 11.0 ppm

NUREG-1801 and ISG-3's description of an aggressive environment is pH < 5.5, chlorides >500 ppm, or sulfates > 1500 ppm. As can be seen from the above data, the MNGP soil conditions are mild.

Final Response: The basis for the determination of mild soil conditions at MNGP is discussed in Technical Report TR-012, Section 3.2.4. The following test results demonstrate that water chemistries for groundwater, well water, and river water are well within acceptable ranges.

USAR Section 2.4.5, Surface Water Quality, provides water samples taken upstream, downstream and at the plant discharge on February 28, 1972. The chemical analyses of the samples were as follows:

Sample Description	Mississippi (Upstream)	Mississippi (Downstream)	Plant Discharge
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Chloride (Cl)	1.4 ppm	0.9 ppm	1.0 ppm
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Groundwater samples taken at MNGP between 1984 and 1991:

Sample Description	Groundwater (1984 - 1991)
pH	7.5 to 8.0
Chloride (Cl)	0.5 to 1.5 ppm
Sulfate (SO4)	6 to 9 ppm

Groundwater samples taken at MNGP in February 2004:
Samples taken at domestic well 11, and monitoring wells 1, 2, and 3.

Sample Description	Domestic well 11	Monitoring well 1	Monitoring well 2	Monitoring well 3
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Sulfate (SO4)	12 mg/L	9 mg/L	22 mg/L	13 mg/L

Well water samples taken at MNGP between 1984 and 1991:
Note: Wells 1 and 2 are located 1000 (+) feet southwest of the power block and are over 85 feet deep.

Sample Description	Well Water (1984 - 1991)
pH	7.7 to 7.9
Chloride (Cl)	15.9 to 17.9 ppm
Sulfate (SO4)	38.6 to 58.5 ppm

Water samples taken at MNGP on 6-30-2003:

Sample Description	Circulating Water (6-30-03)
pH	8.3
Chloride (Cl)	10.8 ppm
Sulfate (SO4)	11.0 ppm

NUREG-1801 and ISG-3's description of an aggressive environment is pH < 5.5, chlorides >500 ppm, or sulfates > 1500 ppm. As can be seen from the above data, the MNGP soil conditions are mild.

Audit Question No.: B2.1.5-04

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lapp **MNGP Owner:** Ray Dennis **Discipline:** Civil

Question: Q4 - Also under Detection of Aging Effects, the enhancement will include evaluation of pipe wall thickness. What methods will be used in the enhanced program to determine pipe wall thickness (Visual, UT, etc.)?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Visual and/or UT inspections will be performed. A visual and UT inspection of buried pipes will be performed at ten year intervals. The last inspection was performed in 1999. An internal visual and UT inspection of the Diesel Fuel Oil Storage Tank, T-44, will also be performed at ten year intervals. The last inspection was performed in 2003. Visual inspections will be performed when buried components are uncovered for other reasons. If the results of the visual inspections warrant it, additional inspections may be performed.

Final Response: Visual and/or UT inspections will be performed. A visual and UT inspection of buried pipes will be performed at ten year intervals. The last inspection was performed in 1999. An internal visual and UT inspection of the Diesel Fuel Oil Storage Tank, T-44, will also be performed at ten year intervals. The last inspection was performed in 2003. Visual inspections will be performed when buried components are uncovered for other reasons. If the results of the visual inspections warrant it, additional inspections may be performed.

Audit Question No.: B2.1.5-05

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lapp **MNGP Owner:** Scott Tradup **Discipline:** Civil

Question: AMP question on B2.1.5 " Buried Tanks and Pipes Inspection Program":

For the Buried Pipes and Tanks Inspection Program, what types of inspections are to be performed for this program before the period of extended operation?

Date Received: 7/21/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: An internal visual and UT inspection of the diesel fuel oil storage tank is performed every 10 years. The last inspection was performed in 2003. A visual and UT inspection of buried piping near the off-gas stack is also performed every 10 years. The last inspection was performed in 1999. Therefore, the only scheduled inspection prior to the period of extended operation is the visual and UT inspections of the buried piping near the off-gas stack. Of course, should any excavation on site provide an opportunity to perform inspections on buried components, those inspections will be performed.

It should be noted that site ground water and soil conditions are mild. Also, previous inspections of the diesel fuel oil storage tank and the buried piping near the off-gas stack have shown minimal degradation even after 35 years. Therefore, keeping on a 10 year inspection schedule is deemed adequate given the site soil conditions and operating experience.

In response to a commitment made to the MNGP Safety Audit Committee, an inspection procedure to inspect a section of buried piping near the off-gas stack was created. The program will be enhanced to include a review of buried components OE to determine if inspections in other areas are warranted.

OE has not identified any locations that are more susceptible to corrosion than any other. The only failures of buried components were on the well water piping system and the instrument air system to the cooling towers. The well water piping failure was postulated to be due to MIC and not a failure of the protective coating. The area of concern of the air line could not be excavated. Therefore, a nearby segment of the air line was excavated and inspected. This section showed no age related degradation. It was concluded that the line failure was not due to age related degradation, but some other mechanism. It should be noted that the air line is not safety related and the line has since been capped and abandoned in place.

Final Response: An internal visual and UT inspection of the diesel fuel oil storage tank is performed every 10 years. The last inspection was performed in 2003. A visual and UT inspection of buried piping near the off-gas stack is also performed every 10 years. The last inspection was performed in 1999. Therefore, the only scheduled inspection prior to the period of extended operation is the visual and UT inspections of the buried piping near the off-gas stack. Of course, should any excavation on site provide an opportunity to perform inspections on buried components, those inspections will be performed.

It should be noted that site ground water and soil conditions are mild. Also, previous inspections of the diesel fuel oil storage tank and the buried piping near the off-gas stack have shown minimal degradation even after 35 years. Therefore, keeping on a 10 year inspection schedule is deemed adequate given the site soil conditions and operating experience.

In response to a commitment made to the MNGP Safety Audit Committee, an inspection procedure to inspect a section of buried piping near the off-gas stack was created. The program will be enhanced to include a review of buried components OE to determine if inspections in other areas are warranted.

OE has not identified any locations that are more susceptible to corrosion than any other. The only failures of buried components were on the well water piping system and the instrument air system to the cooling towers. The well water piping failure was postulated to be due to MIC and not a failure of the protective coating. The area of concern of the air line could not be excavated. Therefore, a nearby segment of the air line was excavated and inspected. This section showed no age related degradation. It was concluded that the line failure was not due to age related degradation, but some other mechanism. It should be noted that the air line is not safety related and the line has since been capped and abandoned in place.

Audit Question No.: 4.4

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Mike Aleksey **Discipline:** TLAA

Question:

1. Provide fluence calculations for core spray lines and spargers, jet pump assembly, in-core instrumentation dry tubes and guide tubes, shroud support structure, SLC distribution pipe, top guide, and core plate.

2. The LRA states that susceptible components were evaluated in accordance with the appropriate BWRVIP guidelines, but does not state that inspections of these components are performed in accordance with the appropriate BWRVIP guidelines. What inspections are performed on these susceptible components?

3. How is multiple failure of the top guide grid beams demonstrated, in the event that threshold fluence for IASCC is exceeded, during normal, upset, emergency, and faulted conditions?

4. How is the oxidizing nature of RCS water controlled?

Date Received: 6/15/2006 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - 4.4

Draft Response:

1) As noted in LRA Section 4.4 only those items expected to exceed a fluence of 5.0E20 n/cm2 are considered susceptible to IASCC. For MNGP these components consist of portions of the top guide, shroud and incore instrumentation dry tubes and guide tubes.

60 year LR extended operating period maximum fluence for these components has been conservatively calculated to be: top guide - 1.66E22 n/cm2, shroud - 3.84E21 n/cm2, and in-core dry/guide tubes - >3.84E21 n/cm2 (these are located inside the shroud)

The core spray lines and spargers are located above the top of the top guide and on the periphery of the upper plenum. At this location the maximum fluence is not expected to exceed 1.0E20 n/cm2 at the end of the 60 year LR extended operating period. The core plate is expected not to exceed 4.03E20 n/cm2. The SLC distribution pipe is located below the core plate so, by comparison, it is expected to be less than the core plate maximum fluence. The shroud support structure is located several feet below the top of the core plate and at the shroud diameter. Consequently it is expected to be much less than the maximum core plate fluence. The jet pumps are located in the annulus (between the shroud and vessel) at approximately active fuel level. At this location the fluence of the jet pumps is bounded by the maximum fluence of the shroud ID (3.84E21 n/cm2) and the maximum fluence of the vessel ID (5.17E18 n/cm2). There are some locations of the jet pumps that, using the conservative core analysis developed for MNGP, may slightly exceed the IASCC threshold (5.0E20 n/cm2) at the end of the 60 year LR extended operating period. It should be noted, however, that IASCC does not in and of itself cause cracking. If other extenuating circumstances (e.g. high stress etc.) are present high fluence can contribute to the formation of cracks. In the case of the jet pumps, stress levels are generally substantially less than yield. This, in addition to the BWRVIP-41 inspections provides assurance that if cracks develop they will be found and mitigated without any safety impact to operation of MNGP. BWRVIP-41 also states that "CASS components are only of concern if cracks are present". The above was discussed with ML prior to his departure from the AMP audit.) The staff acknowledged this position in its BWRVIP-41 LR SER dated June 5, 2001. Also noted in the LR-SER is the fact that further research is being conducted. If this research results in a revision to the BWRVIP recommendations, MNGP will incorporate necessary changes into the MNGP inspection program.

2) The BWRVIP inspections are performed in accordance with EWIs 08.01.01 and .02. (Note these documents discussed with ML prior to his departure.)

3) Discussed sufficiency review RAI with ML and provided copy of MNGP submittal (TAC No. MC6440) prior to his departure.

4) Discussed attributes of water chemistry program with ML prior to departure. Will provide additional information regarding historical data (e.g. dissolved oxygen content etc.) when he returns for their AMR audit.

MNGP implemented a hydrogen water chemistry system in 1989. The hydrogen water chemistry system reduces the oxidizing environment of the RCS coolant by the introducing excess hydrogen to the RCS that combines with the free oxygen produced by radiolysis. Regulation of the feedwater dissolved oxygen to 20-50 ppb during power

operation minimizes corrosion potential.

Final Response: 1) As noted in LRA Section 4.4 only those items expected to exceed a fluence of 5.0E20 n/cm2 are considered susceptible to IASCC. For MNGP these components consist of portions of the top guide, shroud and incore instrumentation dry tubes and guide tubes.

60 year LR extended operating period maximum fluence for these components has been conservatively calculated to be: top guide - 1.66E22 n/cm2, shroud - 3.84E21 n/cm2, and in-core dry/guide tubes - >3.84E21 n/cm2 (these are located inside the shroud)

The core spray lines and spargers are located above the top of the top guide and on the periphery of the upper plenum. At this location the maximum fluence is not expected to exceed 1.0E20 n/cm2 at the end of the 60 year LR extended operating period. The core plate is expected not to exceed 4.03E20 n/cm2. The SLC distribution pipe is located below the core plate so, by comparison, it is expected to be less than the core plate maximum fluence. The shroud support structure is located several feet below the top of the core plate and at the shroud diameter. Consequently it is expected to be much less than the maximum core plate fluence. The jet pumps are located in the annulus (between the shroud and vessel) at approximately active fuel level. At this location the fluence of the jet pumps is bounded by the 60 year maximum fluence of the shroud ID (3.84E21 n/cm2) and the maximum fluence of the vessel ID (5.17E18 n/cm2). There are some locations of the jet pumps that, using the conservative core analysis developed for MNGP, may exceed the IASCC threshold (5.0E20 n/cm2) at the end of the 60 year LR extended operating period. It should be noted, however, that neutron embrittlement does not in and of itself cause cracking. If other extenuating circumstances (e.g. high stress etc.) are present high fluence can contribute to the formation of cracks. In the case of the jet pumps, stress levels are generally substantially less than yield. This, in addition to the BWRVIP-41 inspections provides assurance that if cracks develop they will be found and mitigated without any safety impact to operation of MNGP. BWRVIP-41 also states that "CASS components are only of concern if cracks are present". The staff acknowledged this position in its BWRVIP-41 LR SER dated June 5, 2001. Also noted in the LR-SER is the fact that further research is being conducted. If this research results in a revision to the BWRVIP recommendations, MNGP will incorporate necessary changes into the MNGP inspection program.

2) The BWRVIP guidelines are implemented at MNGP by engineering procedures that define the inspection methods, intervals and acceptance criteria. The procedures include implementation requirements for BWRVIP-26 (Top Guide), BWRVIP-76 (Core Shroud), BWRVIP-47 (Lower Plenum), as well as other BWRVIPs applicable to MNGP. These documents are available for review on-site at MNGP.

3) MNGP's response to the staff's request for additional information describes the commitment to inspect limiting locations of the top guide grid (TAC No. MC6440).

4) MNGP implemented a hydrogen water chemistry system in 1989. The hydrogen water chemistry system reduces the oxidizing environment of the RCS coolant by the introducing excess hydrogen to the RCS that combines with the free oxygen produced by radiolysis. Regulation of the feedwater dissolved oxygen to 20-50 ppb during power operation minimizes corrosion potential.

Audit Question No.: B2.1.13-01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: Preventive actions states "An exception to EPRI TR-107396 and EPRI 1007820 is the plant range for chromate level (500-1800 ppm) is based on prior plant practices and exceeds the range recommended by EPRI." By how much does the plant range for chromates exceed the range recommended by EPRI? What effect has this had on plant items, e.g., pump seals? How often are seals required to be replaced, due to this exceeded chromate range?

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The typical control range for Chromate control in EPRI TR-107396 and EPRI 1007820 is 150 to 300 ppm. The plant has established an administrative limit of 500 to 1,800 based on prior plant practices and a separate limit of 500 to 1,000 ppm based on vendor information. In the mid 1980s chromate levels were as high as 2,200 ppm due to a miscalculation that caused excessive chromate to be added. Since that time, chromate level has been trending downward and is approximately 1,500 ppm. Both EPRI documents note higher concentrations may have an adverse impact on pump seal operation and the plant previously evaluated this impact through the Corrective Action Program. An improved pump seal design was installed in 1992 that has extended seal life to at least three years. The seals are consumables that are periodically replaced. No adverse impacts to the system's License Renewal intended function of maintain pressure integrity have been noted.

Final Response: The typical control range for Chromate control in EPRI TR-107396 and EPRI 1007820 is 150 to 300 ppm. The plant has established an administrative limit of 500 to 1,800 based on prior plant practices and a separate limit of 500 to 1,000 ppm based on vendor information. In the mid 1980s chromate levels were as high as 2,200 ppm due to a miscalculation that caused excessive chromate to be added. Since that time, chromate level has been trending downward and is approximately 1,500 ppm. Both EPRI documents note higher concentrations may have an adverse impact on pump seal operation and the plant previously evaluated this impact through the Corrective Action Program. An improved pump seal design was installed in 1992 that has extended seal life to at least three years. The seals are consumables that are periodically replaced. No adverse impacts to the system's License Renewal intended function of maintain pressure integrity have been noted.

Audit Question No.: B2.1.13-02

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: Preventive actions states "Other chemical parameters noted in EPRI TR-107396 for chemical treatment control and diagnostics and select diagnostic parameters of EPRI 1007820 are not monitored." What other chemical parameters and diagnostic parameters are not monitored? What actions are taken in lieu of these parameters not being monitored?

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: A detailed review of chemical control and diagnostic parameters by corrosion inhibitor type (e.g., chromate based, nitrite based, etc.) was prepared as part of project documentation to support summary statements in the LRA which identify which specific chemical parameters are monitored. Individual parameters not monitored and the basis is included in project documentation. These parameters fall into one of the following categories:
- They are an indirect measure of system performance for which a more direct measure is used instead,
- They are adequately monitored and controlled at the make-up water source,
- They are not applicable to system materials or design (e.g., refrigerant chemicals are not used), or
- They are only applicable to a specific type of corrosion inhibitor not used in the system.

Plant operating experience, chemical control and monitoring activities implemented, and closed cycle cooling water system performance have been acceptable without the use of these additional chemical parameters.

Final Response: A detailed review of chemical control and diagnostic parameters by corrosion inhibitor type (e.g., chromate based, nitrite based, etc.) was prepared as part of project documentation to support summary statements in the LRA which identify which specific chemical parameters are monitored. Individual parameters not monitored and the basis is included in project documentation. These parameters fall into one of the following categories:
- They are an indirect measure of system performance for which a more direct measure is used instead,
- They are adequately monitored and controlled at the make-up water source,
- They are not applicable to system materials or design (e.g., refrigerant chemicals are not used), or
- They are only applicable to a specific type of corrosion inhibitor not used in the system.

Plant operating experience, chemical control and monitoring activities implemented, and closed cycle cooling water system performance have been acceptable without the use of these additional chemical parameters.

Audit Question No.: B2.1.13-03

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: Parameters monitored or inspected states "Non-chemistry testing and inspection techniques, consistent with Section 5.7 of EPRI TR-107396 and Section 8.4 of EPRI 1007820, are used." Explain and justify the differences between GALL inspection and testing recommendations and the above cited EPRI inspection and testing sections.

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: In the "Parameters Monitored or Inspected" aging management program element of the GALL for the CCCW Program the following is stated in part: "in accordance with the standards in EPRI TR-107396 to evaluate system and component performance. For pumps, the parameters monitored include flow and discharge suction pressures. For heat exchangers, the parameters monitored include flow, inlet and outlet temperatures, and differential pressure." This statement was interpreted to mean the Monticello aging management program should be evaluated against both EPRI TR-107396 and the specific parameters listed in the GALL (e.g., pump flow and suction pressure). This was not interpreted to mean the EPRI document should be used in lieu of the GALL specific parameters.

For each closed cooling water system, the specific parameters monitored were noted in the LRA and compared to the GALL parameters. For both EPRI TR-107396 and 1007820, specific parameters were not listed in the GALL but Monticello evaluated EPRI recommendations contained in Sections 5.7 and 8.4 of the respective EPRI reports. It was confirmed through this added comparison that the Monticello program has the same overall objectives for non-chemistry monitoring as the EPRI documents and also implements the same types of monitoring techniques.

In addition to the specific parameters listed in this program element of the GALL, the EPRI documents also discuss the use of non destructive examinations, leakage monitoring, heat transfer, and trending. Monticello implementation of these additional monitoring techniques is described in the Detection of Aging Effects and Monitoring and Trending elements of the aging management program in the LRA.

Final Response: In the "Parameters Monitored or Inspected" aging management program element of the GALL for the CCCW Program the following is stated in part: "in accordance with the standards in EPRI TR-107396 to evaluate system and component performance. For pumps, the parameters monitored include flow and discharge suction pressures. For heat exchangers, the parameters monitored include flow, inlet and outlet temperatures, and differential pressure." This statement was interpreted to mean the Monticello aging management program should be evaluated against both EPRI TR-107396 and the specific parameters listed in the GALL (e.g., pump flow and suction pressure). This was not interpreted to mean the EPRI document should be used in lieu of the GALL specific parameters.

For each closed cooling water system, the specific parameters monitored were noted in the LRA and compared to the GALL parameters. For both EPRI TR-107396 and 1007820, specific parameters were not listed in the GALL but Monticello evaluated EPRI recommendations contained in Sections 5.7 and 8.4 of the respective EPRI reports. It was confirmed through this added comparison that the Monticello program has the same overall objectives for non-chemistry monitoring as the EPRI documents and also implements the same types of monitoring techniques.

In addition to the specific parameters listed in this program element of the GALL, the EPRI documents also discuss the use of non destructive examinations, leakage monitoring, heat transfer, and trending. Monticello implementation of these additional monitoring techniques is described in the Detection of Aging Effects and Monitoring and Trending elements of the aging management program in the LRA.

Audit Question No.: B2.1.13-04

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: Parameters monitored or inspected states: "As an exception to NUREG-1801, inlet RBC heat exchanger temperature is not monitored but outlet temperature and both inlet and outlet temperatures on the raw water side are measured. Also, individual temperature and pressure readings for the RHR and REC pump seal coolers are limited to select temperature and flow locations." How is heat transfer capability of these heat exchangers verified?

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: With the exception of primary containment isolation valves and associated connected piping, the Reactor Building Closed Cooling Water System was included in scope for License Renewal for a "maintain pressure boundary" function only to satisfy 10 CFR 54.4(a)(2) requirements for non safety affecting safety. The RHR and REC pump seal coolers and RBC heat exchanger were included in scope for license renewal to support this "maintain pressure boundary" function. They do not have an intended function of heat transfer for License Renewal. Therefore, confirming heat transfer capability is not part of License Renewal. As these coolers and heat exchangers perform no safety related function, they are not part of the plant program that monitors and trends heat exchanger performance. However, sufficient continuous temperature monitoring at key locations is performed during plant operation to detect overall heat transfer performance. As noted in the LRA and project support documents this includes:

- Raw water inlet and outlet temperature and closed cooling water outlet temperature for the RBC heat exchangers (closed cooling water inlet temperature is not monitored).
- Continuous monitoring and recording of temperatures at various locations around the REC pumps.
- Local flow gauges for individual RHR pump seal cooler flows.

Final Response: With the exception of primary containment isolation valves and associated connected piping, the Reactor Building Closed Cooling Water System was included in scope for License Renewal for a "maintain pressure boundary" function only to satisfy 10 CFR 54.4(a)(2) requirements for non safety affecting safety. The RHR and REC pump seal coolers and RBC heat exchanger were included in scope for license renewal to support this "maintain pressure boundary" function. They do not have an intended function of heat transfer for License Renewal. Therefore, confirming heat transfer capability is not part of License Renewal. As these coolers and heat exchangers perform no safety related function, they are not part of the plant program that monitors and trends heat exchanger performance. However, sufficient continuous temperature monitoring at key locations is performed during plant operation to detect overall heat transfer performance. As noted in the LRA and project support documents this includes:

- Raw water inlet and outlet temperature and closed cooling water outlet temperature for the RBC heat exchangers (closed cooling water inlet temperature is not monitored).
- Continuous monitoring and recording of temperatures at various locations around the REC pumps.
- Local flow gauges for individual RHR pump seal cooler flows.

Audit Question No.: B2.1.13-05

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: Detection of aging effects states: "The extent and schedule of inspections, tests and types of performance monitoring activities implemented are in accordance with EPRI TR-107396 and 1007820, with a few exceptions as noted above." These exceptions are not noted in the LRA with other exceptions. Further, reference is made to these exceptions, but they are not explicitly identified. Please clearly state and justify these exceptions

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Both EPRI TR-107396 and 1007820 include recommendations for chemical parameters and non-chemical parameters. Comparison of chemical parameters monitored by the Monticello CCCW Program to the GALL was primarily addressed in the Preventive Actions, Parameters Monitored or Inspected, and Monitoring and Trending program elements of the LRA. As noted in the Monitoring and Trending element, chemistry sampling frequencies are based on EPRI guidance and vendor recommendations. The "few exceptions" noted in the quoted statement of the RAI is intended to refer to chemistry exceptions only as described in detail in other element discussions. It was not intended to refer to non chemistry monitoring requirements of EPRI which are addressed in the Detection of Aging Effects section of the LRA. The EPRI documents do not identify specific schedules or monitoring frequencies for non chemistry parameters and, instead, identify monitoring objectives and different types of monitoring techniques that may be applied. Monticello compared its program to these objectives and techniques and concluded they are in accordance with the EPRI documents as noted in the above RAI quote. The specific types of non chemistry monitoring techniques employed for the difference closed cycle systems are described in LRA program element Detection of Aging Effects. Therefore, the "few exceptions noted above" is specific to chemistry parameters only as addressed in other program elements of the LRA.

Final Response: Both EPRI TR-107396 and 1007820 include recommendations for chemical parameters and non-chemical parameters. Comparison of chemical parameters monitored by the Monticello CCCW Program to the GALL was primarily addressed in the Preventive Actions, Parameters Monitored or Inspected, and Monitoring and Trending program elements of the LRA. As noted in the Monitoring and Trending element, chemistry sampling frequencies are based on EPRI guidance and vendor recommendations. The "few exceptions" noted in the quoted statement of the RAI is intended to refer to chemistry exceptions only as described in detail in other element discussions. It was not intended to refer to non chemistry monitoring requirements of EPRI which are addressed in the Detection of Aging Effects section of the LRA. The EPRI documents do not identify specific schedules or monitoring frequencies for non chemistry parameters and, instead, identify monitoring objectives and different types of monitoring techniques that may be applied. Monticello compared its program to these objectives and techniques and concluded they are in accordance with the EPRI documents as noted in the above RAI quote. The specific types of non chemistry monitoring techniques employed for the difference closed cycle systems are described in LRA program element Detection of Aging Effects. Therefore, the "few exceptions noted above" is specific to chemistry parameters only as addressed in other program elements of the LRA.

Audit Question No.: B2.1.13-06

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: Detection of aging effects states "pressure integrity evaluations as part of integrated leak rate testing and in-service testing." How does integrated leak rate testing, which is performed on containments, pertain to closed cycle cooling water system performance?

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: In this section of the LRA the statement "as part of integrated leak rate testing" was not intended to imply the results of Type A containment integrated leak rate test are used for determining RBC System containment isolation valve corrosion, though Type A test results could indicate through wall piping corrosion has occurred. The statement was intended to note that local leak rate tests of the RBC primary containment isolation valves, which are periodically performed, can serve as one mean to detect that internal system corrosion may be occurring. Internal visual inspection performed to diagnose failure to successfully pass a local leak rate test could identify if system corrosion is occurring.

Final Response: In this section of the LRA the statement "as part of integrated leak rate testing" was not intended to imply the results of Type A containment integrated leak rate test are used for determining RBC System containment isolation valve corrosion, though Type A test results could indicate through wall piping corrosion has occurred. The statement was intended to note that local leak rate tests of the RBC primary containment isolation valves, which are periodically performed, can serve as one mean to detect that internal system corrosion may be occurring. Internal visual inspection performed to diagnose failure to successfully pass a local leak rate test could identify if system corrosion is occurring.

Audit Question No.: B2.1.13-07

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: Monitoring and trending states: "Established frequencies are based on EPRI TR-107396 and 1007820 guidance and vendor recommendations. These frequencies may vary based on plant operating conditions or equipment performance trends." What is the minimum frequency for performance and functional tests and for tests to evaluate the heat removal capability of the systems?

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The Emergency Diesel Generator cooling loops are the only closed-cycle cooling water system required to perform a heat transfer function in support of License Renewal. Specific testing and frequencies performed to evaluate loop performance and heat removal capability include:

- Conductivity, pH, alkalinity, total iron, total copper, nitrates, nitrite, ammonia, tolytriazole, total aerobic bacteria, and sulfate reducing bacteria are monitored and trended at least quarterly,
- Emergency Diesel Generator coolant heat exchanger performance tests are performed at least once per cycle and the data is trended,
- Every two cycles cleaning, inspection, and eddy current testing of the Emergency Diesel Generator coolant heat exchangers is performed,
- On a quarterly basis as part of Emergency Diesel Generator operability tests, closed coolant level, lube oil temperature, lube oil engine pressure, and engine water temperature are monitored, and
- As part of the 12 year preventive maintenance requirements for the Emergency Diesel Generators, the jacket water pumps are replaced, the jacket water header of the lube oil cooler is visually inspected, and the jacket water system is inspected for any evidence of leakage from piping and joints. A leak detector dye is included in the jacket water treatment to aide in the identification of any leakage.

Final Response: The Emergency Diesel Generator cooling loops are the only closed-cycle cooling water system required to perform a heat transfer function in support of License Renewal. Specific testing and frequencies performed to evaluate loop performance and heat removal capability include:

- Conductivity, pH, alkalinity, total iron, total copper, nitrates, nitrite, ammonia, tolytriazole, total aerobic bacteria, and sulfate reducing bacteria are monitored and trended at least quarterly,
- Emergency Diesel Generator coolant heat exchanger performance tests are performed at least once per cycle and the data is trended,
- Every two cycles cleaning, inspection, and eddy current testing of the Emergency Diesel Generator coolant heat exchangers is performed,
- On a quarterly basis as part of Emergency Diesel Generator operability tests, closed coolant level, lube oil temperature, lube oil engine pressure, and engine water temperature are monitored, and
- As part of the 12 year preventive maintenance requirements for the Emergency Diesel Generators, the jacket water pumps are replaced, the jacket water header of the lube oil cooler is visually inspected, and the jacket water system is inspected for any evidence of leakage from piping and joints. A leak detector dye is included in the jacket water treatment to aide in the identification of any leakage.

Audit Question No.: B2.1.13-08

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: Monitoring and trending states: "Follow-up (increased) sampling and analysis actions are performed when required as part of evaluating corrective action effectiveness." What requires increased sampling and analysis?

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The site Corrective Action Program includes requirements to take follow-up actions when required to evaluate corrective action effectiveness. For the purposes of this aging management program, follow-up actions could take the form of increased system performance monitoring and/or chemistry monitoring depending on the nature of the issue and its apparent cause. The site corrective action procedure invokes the fleet procedure which requires review of work performed to assure adequate resolution of issues. Additionally, the site chemistry procedure requires verification of effectiveness of corrective actions such as those taken to restore acceptable closed-cycle cooling water system chemistry.

Final Response: The site Corrective Action Program includes requirements to take follow-up actions when required to evaluate corrective action effectiveness. For the purposes of this aging management program, follow-up actions could take the form of increased system performance monitoring and/or chemistry monitoring depending on the nature of the issue and its apparent cause. The site corrective action procedure invokes the fleet procedure which requires review of work performed to assure adequate resolution of issues. Additionally, the site chemistry procedure requires verification of effectiveness of corrective actions such as those taken to restore acceptable closed-cycle cooling water system chemistry.

Audit Question No.: B2.1.13-09

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: Monitoring and trending states: "System and component operability tests are typically performed on a more frequent basis than once per cycle whereas more intrusive inspections (disassembly, eddy current testing, etc.) are performed less frequently but at sufficient intervals to detect the impact of aging effects." How are these less frequent but "sufficient intervals" determined?

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Operability test frequencies are based on satisfying plant Technical Specification requirements. These frequencies are established by regulation and are based on a number of inputs such as system reliability, industry operating experience, and safety risk. Some less frequent tests are also required by Technical Specifications. For those test frequencies not established by regulation, intervals are defined based on vendor recommendations, industry experience, prior commitments contained in the CLB, and plant operating experience. For example, the Emergency Diesel Generator (EDG) coolant heat exchangers are cleaned, inspected, and eddy current tested on a periodic basis as part of a major EDG preventive maintenance task. The frequency established for this task is based on owner group recommendations as noted in the purpose section of the plant procedure. The procedure also notes the heat exchanger and piping inspections satisfy prior NRC commitments. Typically, the reason (basis) for performing the test or inspection is contained in the purpose section of the procedure.

A number of plant operating parameters are monitored on a daily or continuous basis. For example, as part of routine operator rounds coolant level, pressure, and temperature are logged for the #14 air compressor (which contains a closed cycle cooling loop included in this aging management program).

Unacceptable trends or inspection results would be entered into the Corrective Action Program for further evaluation. These evaluations could lead to more frequent testing or maintenance.

Final Response: Operability test frequencies are based on satisfying plant Technical Specification requirements. These frequencies are established by regulation and are based on a number of inputs such as system reliability, industry operating experience, and safety risk. Some less frequent tests are also required by Technical Specifications. For those test frequencies not established by regulation, intervals are defined based on vendor recommendations, industry experience, prior commitments contained in the CLB, and plant operating experience. For example, the Emergency Diesel Generator (EDG) coolant heat exchangers are cleaned, inspected, and eddy current tested on a periodic basis as part of a major EDG preventive maintenance task. The frequency established for this task is based on owner group recommendations as noted in the purpose section of the plant procedure. The procedure also notes the heat exchanger and piping inspections satisfy prior NRC commitments. Typically, the reason (basis) for performing the test or inspection is contained in the purpose section of the procedure.

A number of plant operating parameters are monitored on a daily or continuous basis. For example, as part of routine operator rounds coolant level, pressure, and temperature are logged for the #14 air compressor (which contains a closed cycle cooling loop included in this aging management program).

Unacceptable trends or inspection results would be entered into the Corrective Action Program for further evaluation. These evaluations could lead to more frequent testing or maintenance.

Audit Question No.: B2.1.13-10

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: Acceptance criteria states: "Corrosion inhibitor and coolant concentrations are maintained within limits based on a combination of EPRI 1007820 guidelines, vendor recommendations, and plant experience." Do the resulting inhibitor and coolant concentrations result in exceeding EPRI ranges? What effect does this have on managing the effects of aging?

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: As noted in the Acceptance Criteria section of the LRA, the RBC System chromate level is monitored to a range above that recommended by EPRI 1007820. Impact of this operating range on system performance was discussed in response to RAI B2.1.13-01. The remaining chemical parameter monitored for the RBC System for which an operating range is specific in EPRI 1007820 is pH. The Monticello operating range for this parameter is more restrictive than (within) the range specified in EPRI 1007820.

For the EDG System, all monitored parameters have specified ranges that are more restrictive than (within) the normal operating ranges of EPRI 1007820.

For the HTV System, chemical ranges are monitored in accordance with vendor recommendations and do not have a corresponding normal operating range specified in EPRI 1007820.

For the closed cooling loop of the #14 Air Compressor, chemical ranges are monitored for trending purposes and are based on plant experience. Monticello maintains the glycol concentration above the minimum recommended in EPRI 1007820. EPRI 1007820 recommends glycol percent volume remain within 30% to 60%. A range above 30% is specified to avoid becoming a nutrient for microbiological growth. The concentration at Monticello is maintained at approximately 50%.

Finally as noted in the Operating Experience section of the LRA, no examples of closed-cycle component cooling system functional failures due to inadequate chemistry control were identified.

Final Response: As noted in the Acceptance Criteria section of the LRA, the RBC System chromate level is monitored to a range above that recommended by EPRI 1007820. Impact of this operating range on system performance was discussed in response to RAI B2.1.13-01. The remaining chemical parameter monitored for the RBC System for which an operating range is specific in EPRI 1007820 is pH. The Monticello operating range for this parameter is more restrictive than (within) the range specified in EPRI 1007820.

For the EDG System, all monitored parameters have specified ranges that are more restrictive than (within) the normal operating ranges of EPRI 1007820.

For the HTV System, chemical ranges are monitored in accordance with vendor recommendations and do not have a corresponding normal operating range specified in EPRI 1007820.

For the closed cooling loop of the #14 Air Compressor, chemical ranges are monitored for trending purposes and are based on plant experience. Monticello maintains the glycol concentration above the minimum recommended in EPRI 1007820. EPRI 1007820 recommends glycol percent volume remain within 30% to 60%. A range above 30% is specified to avoid becoming a nutrient for microbiological growth. The concentration at Monticello is maintained at approximately 50%.

Finally as noted in the Operating Experience section of the LRA, no examples of closed-cycle component cooling system functional failures due to inadequate chemistry control were identified.

Audit Question No.: B2.1.13-11

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: 1. Exception 1 states that the MNGP program generally meets the criteria of both revisions of the EPRI closed cooling water chemistry guidelines. Does MNGP fully implement EPRI 1007820 guidelines? If not, then what exceptions to EPRI 1007820 does MNGP take?

Date Received: 7/20/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Monticello does not fully implement EPRI 1007820. As noted in the LRA, there are some exceptions to monitoring specific parameters and ranges based on system design and License Renewal intended functions (e.g., freon levels are not monitored as recommended by EPRI since none of the in-scope closed-cycle cooling water systems interface with refrigerant systems). These are discussed in more detail in response to RAI B2.1.13-12 and B2.1.13-14. Treatment program and monitoring recommendations for closed-cycle cooling water systems are contained in Chapters 5 and 8 of EPRI 1007820.

For each chemical inhibitor type (e.g., chromate, blended glycol formulations, etc.), control and diagnostic parameters are listed in Chapter 5. Normal operating ranges for control parameters, with Action Levels, and monitoring frequencies are provided. For diagnostic parameters, only monitoring frequencies are specified with a requirement for evaluation of trend results.

For the RBC System, control parameters are monitored at the frequency specified in 1007820 for Tier 2 Systems (Tier 2 Systems are not safety related and do not immediately impact plant operation). For the cooling loops of the DGN System, monitoring is performed on a quarterly basis consistent with operability testing frequency of the diesels. This is consistent with EPRI 1007820 for systems operated on an intermittent basis. For the piping and heating coils of the HTV System, chemical parameters and frequencies are not specified in EPRI 1007820, However, control parameters are monitored weekly when the system is in operation. For the closed cooling loop of the #14 Air Compressor of the AIR System, control parameters are measured twice per year, exceeding the annual frequency requirements of EPRI 1007820 for Tier 2 Systems. Action Levels and required response times contained in 1007820 for closed-cycle cooling water systems are not contained in plant procedures. However, plant procedures require the issuance of an Action Request and evaluation via the Corrective Action Program for chemistry parameters found outside of limit. Follow-up (increased) sampling and analysis actions are performed when required as part of evaluating corrective action effectiveness. Chemistry procedures require verification of effectiveness of correction actions.

The additional monitoring techniques and considerations in Chapter 8 of EPRI 1007820 are implemented for closed-cycle cooling water systems based on design, license renewal intended function, plant operating experience, and aging effects requiring management. This includes internal component inspections, ultrasonic testing, eddy current testing of heat exchanger tubes, monitoring heat transfer performance, surge tank level monitoring for system leakage, system leak examinations during walk downs and tests, and other system performance monitoring actions.

Final Response: Monticello does not fully implement EPRI 1007820. As noted in the LRA, there are some exceptions to monitoring specific parameters and ranges based on system design and License Renewal intended functions (e.g., freon levels are not monitored as recommended by EPRI since none of the in-scope closed-cycle cooling water systems interface with refrigerant systems). These are discussed in more detail in response to RAI B2.1.13-12 and B2.1.13-14. Treatment program and monitoring recommendations for closed-cycle cooling water systems are contained in Chapters 5 and 8 of EPRI 1007820.

For each chemical inhibitor type (e.g., chromate, blended glycol formulations, etc.), control and diagnostic parameters are listed in Chapter 5. Normal operating ranges for control parameters, with Action Levels, and monitoring frequencies are provided. For diagnostic parameters, only monitoring frequencies are specified with a requirement for evaluation of trend results.

For the RBC System, control parameters are monitored at the frequency specified in EPRI 1007820 for Tier 2 Systems (Tier 2 Systems are not safety related and do not immediately impact plant operation). For the cooling loops of the DGN System, monitoring is performed on a quarterly basis consistent with operability testing frequency of the diesels. This is consistent with EPRI 1007820 for systems operated on an intermittent basis. For the piping and heating coils of the HTV System, chemical parameters and frequencies are not specified in EPRI 1007820, However, control parameters are monitored weekly when the system is in operation. For the closed cooling loop of the #14 Air Compressor of the AIR System, control parameters are measured twice per year, exceeding the annual frequency requirements of EPRI 1007820 for Tier 2 Systems.

Action Levels and required response times contained in EPRI 1007820 for closed-cycle cooling water systems are not contained in plant procedures. However, plant procedures require the issuance of an Action Request and evaluation via the Corrective Action Program for chemistry parameters found outside of limit. Follow-up (increased) sampling and analysis actions are performed when required as part of evaluating corrective action effectiveness. Chemistry procedures require verification of effectiveness of correction actions.

The additional monitoring techniques and considerations in Chapter 8 of EPRI 1007820 are implemented for closed-cycle cooling water systems based on design, license renewal intended function, plant operating experience, and aging effects requiring management. This includes internal component inspections, ultrasonic testing, eddy current testing of heat exchanger tubes, monitoring heat transfer performance, surge tank level monitoring for system leakage, system leak examinations during walk downs and tests, and other system performance monitoring actions.

Audit Question No.: B2.1.13-12

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: 2. Exception 2 states that some of the chemical parameters recommended for routine monitoring by EPRI guidelines are not included in the closed-cycle cooling water system program. Which parameters are not included? How does system design preclude the need for monitoring some chemicals?

Date Received: 7/20/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: As noted in the LRA, many of the chemical parameters recommended by EPRI TR-107396 and 1007820 are monitored by Monticello for the various inhibitor types (e.g., chromate) used in closed-cycle cooling systems. The LRA further notes system design precludes the need to monitor some of these parameters (e.g., freon is not used, raw water is not used for makeup, the system does not interface with a radioactive source) and operating and inspection activities preclude the need to monitor others. Specific parameters monitored or excluded are noted in the LRA for each inhibitor type closed-cycle cooling water system and itemized on a parameter basis in project documents. Specific to each closed-cycle cooling water system, parameters recommended by EPRI TR-107396 and/or EPRI 1007820 that are excluded and the basis for exclusion, are:

For the RBC System:

· Conductivity - As noted in both EPRI guidelines, conductivity is an indirect measure of concentration of chemical treatment and may also provide indication of system leaks. For the RBC System conductivity is not measured; however, direct measure of critical chemical treatment parameters is performed and other means are used both continuously and periodically to detect leakage and the potential for leakage as described further in the Parameters Monitored or Inspected Program Element in the LRA.
· Corrosion Inhibitor/Conductivity Ratio - Corrosion inhibitor level is monitored but not conductivity or the corrosion inhibitor to conductivity ratio. As noted in the EPRI guidelines, this is especially valuable in nitrite-treated systems and helpful in identifying system leaks. The RBC System is chromate-based and relies on other monitoring methods considered effective for identifying leaks, such as surge tank level, and system pressures.
· Chloride - Chloride is monitored and controlled to levels well below the critical concentrations noted in the EPRI guidelines as part of the demineralized water source – which provides makeup to the RBC System. Use of stainless steel in the RBC System is minimal and restricted to the RHR and REC pump seal coolers and instrument tubing. Chemistry control on the tube side of the coolers includes chemical control for stress corrosion cracking as part of the Plant Chemistry Program – water sources on the tube side include control rod drive hydraulic, reactor coolant, condensate storage tank, and suppression pool (torus) water. As noted in EPRI TR-107396, stress corrosion cracking is minimized with pH > 7.0. For the RBC System, pH is maintained in a range of 9.0 to 9.8. Further, system operating temperature is <130ºF which is below the threshold at which chloride becomes a concern for stainless steel.
· Fluoride - Fluoride levels are not monitored; however, makeup water originates from a non-fluoridated source (well water) and fluoride levels are not expected to be significant. Per EPRI TR-107396, fluoride concentrations in closed-cycle cooling water systems are not detrimental to system components nor do they cause significant stress corrosion cracking. Further, system operating temperature is <130ºF which is below the threshold at which fluoride becomes a concern for stainless steel.
· Sulfate - As with chlorides, sulfate levels are monitored and controlled to well below the critical concentrations noted in EPRI TR-107396 as part of the demineralized water source – which provides makeup to the RBC System. As noted in EPRI 1007820, sulfate contamination comes from poor quality makeup water, service water in-leakage, or biocide additions. The RBC System is not subject to these conditions.
· Iron and Copper - Monitoring corrosion products is a direct indication of the presence of corrosion. This monitoring is not performed for the RBC System. As noted in the Parameters Monitored or Inspected Element, both existing and enhancement actions to inspect and test internal portions of the RBC System based on plant operating experience are sufficient to evaluate the occurrence and rate of corrosion (e.g., prior non destructive examinations, proposed one time inspections, heat exchanger performance tests, etc.).
· Calcium and Magnesium - Calcium and magnesium levels are not monitored. Both EPRI TR-107396 and 1007820 indicate these parameters should be monitored if raw water makeup is used. Raw water makeup is not used at Monticello and the RBC System is provided treated water from the demineralized water source for makeup.
· Freon - Refrigerant chemicals are not monitored. The system does not interface directly with any refrigerant cooling sources.

For the cooling loops of the DGN System:

· Corrosion Inhibitor/Conductivity Ratio - The corrosion inhibitor to conductivity ratio is not calculated or trended; however, both parameters are measured individually and

trended. As noted in the EPRI guidelines, this is especially valuable in nitrite-treated systems and helpful in identifying system leaks. System performance monitoring methods are relied upon and considered effective for identifying leaks.
· Total Organic Carbon - Total organic carbon is not monitored; however, total aerobic bacteria and sulfate reducing bacteria concentrations are monitored and trended on a periodic basis.
· Dissolved Oxygen - The loops are closed loop and do not require significant makeup, therefore, dissolved oxygen is not monitored.
· Fluoride - The loops do not contain stainless steel components.
· Sulfate - As with chlorides, sulfate levels are monitored and controlled to well below the critical concentrations noted in EPRI TR-107396 as part of the demineralized water source - which provides makeup to the cooling loops. As noted in EPRI 1007820, sulfate contamination comes from poor quality makeup water, service water in-leakage, or biocide additions. The loops are not subject to these conditions.
· Calcium and Magnesium - Calcium and magnesium levels are not monitored. Both EPRI TR-107396 and 1007820 indicate these parameters should be monitored if raw water makeup is used. Raw water makeup is not used at Monticello and the loops are provided treated water from the demineralized water source for makeup.
· Freon - Refrigerant chemicals are not monitored. The loops do not interface directly with any refrigerant cooling sources.
· Radionuclides - Radionuclides are not monitored, the loops do not interface with any potentially radioactive sources.

For the piping and heating coils of the HTV System:

The piping and heating coils of the HTV System utilize a sulfite-based corrosion inhibitor. The EPRI guidelines do not discuss the use of sulfite as an oxygen-de-aerator. Chemical range for the corrosion inhibitor is established in accordance with vendor recommendations. Consistent with EPRI TR-107396 and 1007820, pH, corrosion inhibitor concentration, conductivity, and the presence of radionuclides (total gamma activity) levels are periodically monitored. Other chemical parameters are not monitored nor is specific monitoring performed to detect microbiological growth. However, pH is maintained very high (11.5 to 12) thus minimizing the potential for growth. The system does not interface with refrigerant type coolants, and the makeup water is from a demineralized water source. Therefore, the same reasons apply for not monitoring other chemical parameters recommended by EPRI for other types of inhibitor based systems.

For the closed cooling loop used on the #14 Air Compressor (portion of the AIR System):

The closed cooling loop used on the #14 Air Compressor (portion of the AIR System) utilizes an inhibited ethylene glycol solution. The solution contains a minor percentage of diethylene glycol. Consistent with EPRI TR-107396 and 1007820 for blended glycol formulations a number of key parameters are measured and sampling is performed on a more frequent basis than recommended by EPRI. All control parameters and diagnostic parameters are monitored with the exception of level of corrosion products and those parameters identified in EPRI as manufacturer specific. The level of corrosion inhibitor is monitored and routine performance monitoring of both coolant levels and heat exchanger performance (system temperatures) are performed which provide insights on the possible presence of corrosion products.

Final Response: As noted in the LRA, many of the chemical parameters recommended by EPRI TR-107396 and 1007820 are monitored by Monticello for the various inhibitor types (e.g., chromate) used in closed-cycle cooling systems. The LRA further notes system design precludes the need to monitor some of these parameters (e.g., freon is not used, raw water is not used for makeup, the system does not interface with a radioactive source) and operating and inspection activities preclude the need to monitor others. Specific parameters monitored or excluded are noted in the LRA for each inhibitor type closed-cycle cooling water system and itemized on a parameter basis in project documents. Specific to each closed-cycle cooling water system, parameters recommended by EPRI TR-107396 and/or EPRI 1007820 that are excluded and the basis for exclusion, are:

For the RBC System:

· Conductivity - As noted in both EPRI guidelines, conductivity is an indirect measure of concentration of chemical treatment and may also provide indication of system leaks. For the RBC System conductivity is not measured; however, direct measure of critical chemical treatment parameters is performed and other means are used both continuously and periodically to detect leakage and the potential for leakage as described further in the Parameters Monitored or Inspected Program Element in the LRA.
· Corrosion Inhibitor/Conductivity Ratio - Corrosion inhibitor level is monitored but not conductivity or the corrosion inhibitor to conductivity ratio. As noted in the EPRI guidelines, this is especially valuable in nitrite-treated systems and helpful in identifying system leaks. The RBC System is chromate-based and relies on other monitoring methods considered effective for identifying leaks, such as surge tank level, and system pressures.

· Chloride - Chloride is monitored and controlled to levels well below the critical concentrations noted in the EPRI guidelines as part of the demineralized water source – which provides makeup to the RBC System. Use of stainless steel in the RBC System is minimal and restricted to the RHR and REC pump seal coolers and instrument tubing. Chemistry control on the tube side of the coolers includes chemical control for stress corrosion cracking as part of the Plant Chemistry Program – water sources on the tube side include control rod drive hydraulic, reactor coolant, condensate storage tank, and suppression pool (torus) water. As noted in EPRI TR-107396, stress corrosion cracking is minimized with pH > 7.0. For the RBC System, pH is maintained in a range of 9.0 to 9.8. Further, system operating temperature is <130ºF which is below the threshold at which chloride becomes a concern for stainless steel.
· Fluoride - Fluoride levels are not monitored; however, makeup water originates from a non-fluoridated source (well water) and fluoride levels are not expected to be significant. Per EPRI TR-107396, fluoride concentrations in closed-cycle cooling water systems are not detrimental to system components nor do they cause significant stress corrosion cracking. Further, system operating temperature is <130ºF which is below the threshold at which fluoride becomes a concern for stainless steel.
· Sulfate - As with chlorides, sulfate levels are monitored and controlled to well below the critical concentrations noted in EPRI TR-107396 as part of the demineralized water source – which provides makeup to the RBC System. As noted in EPRI 1007820, sulfate contamination comes from poor quality makeup water, service water in-leakage, or biocide additions. The RBC System is not subject to these conditions.
· Iron and Copper - Monitoring corrosion products is a direct indication of the presence of corrosion. This monitoring is not performed for the RBC System. As noted in the Parameters Monitored or Inspected Element, both existing and enhancement actions to inspect and test internal portions of the RBC System based on plant operating experience are sufficient to evaluate the occurrence and rate of corrosion (e.g., prior non destructive examinations, proposed one time inspections, heat exchanger performance tests, etc.).
· Calcium and Magnesium - Calcium and magnesium levels are not monitored. Both EPRI TR-107396 and 1007820 indicate these parameters should be monitored if raw water makeup is used. Raw water makeup is not used at Monticello and the RBC System is provided treated water from the demineralized water source for makeup.
· Freon - Refrigerant chemicals are not monitored. The system does not interface directly with any refrigerant cooling sources.

For the cooling loops of the DGN System:

· Corrosion Inhibitor/Conductivity Ratio - The corrosion inhibitor to conductivity ratio is not calculated or trended; however, both parameters are measured individually and trended. As noted in the EPRI guidelines, this is especially valuable in nitrite-treated systems and helpful in identifying system leaks. System performance monitoring methods are relied upon and considered effective for identifying leaks.
· Total Organic Carbon - Total organic carbon is not monitored; however, total aerobic bacteria and sulfate reducing bacteria concentrations are monitored and trended on a periodic basis.
· Dissolved Oxygen - The loops are closed loop and do not require significant makeup, therefore, dissolved oxygen is not monitored.
· Fluoride - The loops do not contain stainless steel components.
· Sulfate - As with chlorides, sulfate levels are monitored and controlled to well below the critical concentrations noted in EPRI TR-107396 as part of the demineralized water source - which provides makeup to the cooling loops. As noted in EPRI 1007820, sulfate contamination comes from poor quality makeup water, service water in-leakage, or biocide additions. The loops are not subject to these conditions.
· Calcium and Magnesium - Calcium and magnesium levels are not monitored. Both EPRI TR-107396 and 1007820 indicate these parameters should be monitored if raw water makeup is used. Raw water makeup is not used at Monticello and the loops are provided treated water from the demineralized water source for makeup.
· Freon - Refrigerant chemicals are not monitored. The loops do not interface directly with any refrigerant cooling sources.
· Radionuclides - Radionuclides are not monitored, the loops do not interface with any potentially radioactive sources.

For the piping and heating coils of the HTV System:

The piping and heating coils of the HTV System utilize a sulfite-based corrosion inhibitor. The EPRI guidelines do not discuss the use of sulfite as an oxygen-de-aerator. Chemical range for the corrosion inhibitor is established in accordance with vendor recommendations. Consistent with EPRI TR-107396 and 1007820, pH, corrosion inhibitor concentration, conductivity, and the presence of radionuclides (total gamma activity) levels are periodically monitored. Other chemical parameters are not monitored nor is specific monitoring performed to detect microbiological growth. However, pH is maintained very high (11.5 to 12) thus minimizing the potential for growth. The system does not interface with refrigerant type coolants, and the makeup water is from a demineralized water source. Therefore, the same reasons apply for not monitoring other chemical parameters recommended by EPRI for other types of inhibitor based systems.

For the closed cooling loop used on the #14 Air Compressor (portion of the AIR System):

The closed cooling loop used on the #14 Air Compressor (portion of the AIR System) utilizes an inhibited ethylene glycol solution. The solution contains a minor percentage of diethylene glycol. Consistent with EPRI TR-107396 and 1007820 for blended glycol formulations a number of key parameters are measured and sampling is performed on a more frequent basis than recommended by EPRI. All control parameters and diagnostic parameters are monitored with the exception of level of corrosion products and those parameters identified in EPRI as manufacturer specific. The level of corrosion inhibitor is monitored and routine performance monitoring of both coolant levels and heat exchanger performance (system temperatures) are performed which provide insights on the possible presence of corrosion products.

Audit Question No.: B2.1.13-13

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: 3. Exception 3 states that some of the heat exchanger and pump performance parameters recommended by NUREG-1801 are not monitored for specific pumps or smaller coolers serviced by the closed-cooling water systems. Why not? What is done to assure pump and heat exchanger performance? When components are screened into scope of license renewal, management of aging cannot be ignored because some components have only a pressure boundary function.

Date Received: 7/20/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: As noted in the LRA, system performance monitoring techniques are relied upon to monitor for aging effects in addition to the use of chemical inhibitors to mitigate corrosion. In many cases, the monitoring techniques are identical to those specified in NUREG-1801. In those cases where exceptions were taken, existing performance monitoring techniques were found to be sufficient based on plant operating experience to detect for the presence of aging effects and to confirm the effectiveness of chemistry control. As noted in the LRA, only the cooling loops for the DGN System perform a License Renewal heat transfer function. All remaining closed loop systems in scope for License Renewal were included for pressure boundary only. No components were screened out of the aging management program on the basis that they only perform a pressure boundary function. However, system performance monitoring techniques in these cases were selected to provide insights on the pressure retention License Renewal intended function and not a heat transfer function. In a few cases it was determined that, even though degradation has not been noted based on plant operating experience, existing monitoring was not sufficient to confirm the effectiveness of chemistry in mitigating aging effects of pressure boundary components. An enhancement was included in the LRA to address these areas as follows: "A one time inspection will be performed to monitor the effects of corrosion on select portions of the closed-cycle cooling water systems that perform a pressure integrity intended function." If results of these one time inspections determine routine examinations are required, they will be added to the closed-cycle cooling water system aging management program.

Specific monitoring performed and exceptions for pumps and heat exchangers of each closed-cycle cooling water system are:

The RBC System includes the RBC heat exchangers and pumps, RHR System pump seal coolers, REC System pump lower and upper seal coolers, CRD System pump thrust bearing coolers, and CRD System pump speed increaser lube oil heat exchangers. These components are included in License Renewal scope as their pressure integrity failure could adversely impact the operation of nearby safety related equipment. They are not required to support a heat transfer function. Consistent with NUREG-1801, monitored RBC System pump parameters include flow and discharge and suction pressure which are logged daily. As an exception to NUREG-1801, inlet RBC heat exchanger temperature is not monitored but outlet temperature and both inlet and outlet temperatures on the raw water side are measured. Also, individual temperature and pressure readings for the RHR and REC pump seal coolers are limited to select temperature and flow locations. Continuous monitoring of RBC surge tank level, various system temperatures and flow, and radionuclide levels are also available and alarm on out of range values. These parameters provide indication of pressure integrity failures within this closed loop system. Reduced heat transfer performance (from temperature monitoring results) can also be indicative of internal corrosion.

These system and component monitoring techniques have been effective, based on plant operating experience, in managing the effects of corrosion on RBC System components included in the scope of License Renewal. Additionally, ultrasonic test measurements of pipe wall thickness to determine the extent of corrosion on select portions of RBC System piping inside the drywell were performed which confirmed the effectiveness of chemistry. The measurements included piping connected to the REC System pump seal coolers. However, no direct inspection for confirming chemistry is effective in mitigating the effects of corrosion on the RBC System portion connected to the RHR System pump seal coolers or CRD System pump coolers has been performed. As an enhancement, a one time inspection will be performed to monitor the effects of corrosion of the RHR System pump coolers and CRD System pump coolers and nearby connected piping.

For the cooling loops of the EDG System, non-chemical performance monitoring methods are used to confirm the effectiveness of chemistry in mitigating corrosion. As an exception to NUREG-1801, the EDG jacket water pump suction and discharge pressures and flow are not measured; however, water temperature, closed coolant level, lube oil pressure, and lube oil temperature are monitored on a quarterly basis as part of EDG operability tests. As part of the 12 year preventive maintenance requirements for the EDGs, the jacket water pumps are replaced, the jacket water header of the lube oil cooler is visually inspected, and the jacket water system is inspected for any evidence of leakage from piping or joints (a leak detector dye is used in the coolant). As an exception to NUREG-1801, differential pressure across the EDG coolant heat exchangers is not monitored, but heat exchanger performance testing is performed on a periodic basis by gathering temperature and flow results. Eddy current testing is also performed periodically. These testing methods, combined with chemical control and monitoring, have been effective in managing corrosion aging effects based on plant operating

experience.

Chemistry control and monitoring effectively manage aging effects of the piping and heating coils of the HTV System. As an exception to NUREG-1801, system and component performance monitoring is not performed. The recommended pump performance parameters are not monitored, and the system contains no heat exchangers. The system contains a number of heating coils as it provides heating to various plant locations. Only select portions of the piping system and heater coils are included in License Renewal scope for pressure integrity only. Some of the heating coils are visually inspected for leaks on a periodic basis. Based on plant operating experience, chemistry control and inspection practices to date of the piping and heating coils have been effective in minimizing the impacts of corrosion and system leakage. As an enhancement to the program, a one time inspection will be performed to monitor the effects of corrosion in select portions of the system within the scope of License Renewal.

In addition to chemistry checks and coolant additions as needed, periodic non-chemical monitoring techniques are used to evaluate performance of the closed cooling loop used for the #14 Air Compressor. Ethylene glycol is used for the heat transfer medium with a radiator and fan for heat rejection. Though the heat transfer function is not in scope for License Renewal, many of the same periodic monitoring techniques can be used to detect leakage or performance degradation that may ultimately impact the License Renewal pressure boundary function. In addition to a local low coolant flow alarm, a number of parameters are monitored and logged on a routine basis including coolant pump suction and discharge pressure, surge tank coolant and oil levels, and various coolant and compressor temperatures and pressures (i.e., compressor oil pressure and temperature, compressor air inlet and outlet temperature, intercooler pressure, compressor coolant inlet and outlet temperature, and aftercooler coolant temperature). As part of periodic compressor maintenance activities, visual inspections of the intercooler, aftercooler, oil cooler, and cooling unit are performed to identify leaks or corrosion. Depending on performance trends, the coolant (internal) side of the various coolers may require inspection and cleaning. Reduced heat transfer performance (from temperature monitoring results) can also be indicative of internal corrosion.

Final Response: As noted in the LRA, system performance monitoring techniques are relied upon to monitor for aging effects in addition to the use of chemical inhibitors to mitigate corrosion. In many cases, the monitoring techniques are identical to those specified in NUREG-1801. In those cases where exceptions were taken, existing performance monitoring techniques were found to be sufficient based on plant operating experience to detect for the presence of aging effects and to confirm the effectiveness of chemistry control. As noted in the LRA, only the cooling loops for the DGN System perform a License Renewal heat transfer function. All remaining closed loop systems in scope for License Renewal were included for pressure boundary only. No components were screened out of the aging management program on the basis that they only perform a pressure boundary function. However, system performance monitoring techniques in these cases were selected to provide insights on the pressure retention License Renewal intended function and not a heat transfer function. In a few cases it was determined that, even though degradation has not been noted based on plant operating experience, existing monitoring was not sufficient to confirm the effectiveness of chemistry in mitigating aging effects of pressure boundary components. An enhancement was included in the LRA to address these areas as follows: "A one time inspection will be performed to monitor the effects of corrosion on select portions of the closed-cycle cooling water systems that perform a pressure integrity intended function." If results of these one time inspections determine routine examinations are required, they will be added to the closed-cycle cooling water system aging management program.

Specific monitoring performed and exceptions for pumps and heat exchangers of each closed-cycle cooling water system are:

The RBC System includes the RBC heat exchangers and pumps, RHR System pump seal coolers, REC System pump lower and upper seal coolers, CRD System pump thrust bearing coolers, and CRD System pump speed increaser lube oil heat exchangers. These components are included in License Renewal scope as their pressure integrity failure could adversely impact the operation of nearby safety related equipment. They are not required to support a heat transfer function. Consistent with NUREG-1801, monitored RBC System pump parameters include flow and discharge and suction pressure which are logged daily. As an exception to NUREG-1801, inlet RBC heat exchanger temperature is not monitored but outlet temperature and both inlet and outlet temperatures on the raw water side are measured. Also, individual temperature and pressure readings for the RHR and REC pump seal coolers are limited to select temperature and flow locations. Continuous monitoring of RBC surge tank level, various system temperatures and flow, and radionuclide levels are also available and alarm on out of range values. These parameters provide indication of pressure integrity failures within this closed loop system. Reduced heat transfer performance (from temperature monitoring results) can also be indicative of internal corrosion.

These system and component monitoring techniques have been effective, based on plant operating experience, in managing the effects of corrosion on RBC System components included in the scope of License Renewal. Additionally, ultrasonic test measurements of pipe wall thickness to determine the extent of corrosion on select portions of RBC System piping inside the drywell were performed which confirmed the effectiveness of chemistry. The measurements included piping connected to the REC System pump seal coolers. However, no direct inspection for confirming chemistry is effective in mitigating the effects of corrosion on the RBC System portion connected to the RHR System pump seal coolers or CRD System pump coolers has been performed. As an enhancement, a one time inspection will be performed to monitor the effects of

corrosion of the RHR System pump coolers and CRD System pump coolers and nearby connected piping.

For the cooling loops of the EDG System, non-chemical performance monitoring methods are used to confirm the effectiveness of chemistry in mitigating corrosion. As an exception to NUREG-1801, the EDG jacket water pump suction and discharge pressures and flow are not measured; however, water temperature, closed coolant level, lube oil pressure, and lube oil temperature are monitored on a quarterly basis as part of EDG operability tests. As part of the 12 year preventive maintenance requirements for the EDGs, the jacket water pumps are replaced, the jacket water header of the lube oil cooler is visually inspected, and the jacket water system is inspected for any evidence of leakage from piping or joints (a leak detector dye is used in the coolant). As an exception to NUREG-1801, differential pressure across the EDG coolant heat exchangers is not monitored, but heat exchanger performance testing is performed on a periodic basis by gathering temperature and flow results. Eddy current testing is also performed periodically. These testing methods, combined with chemical control and monitoring, have been effective in managing corrosion aging effects based on plant operating experience.

Chemistry control and monitoring effectively manage aging effects of the piping and heating coils of the HTV System. As an exception to NUREG-1801, system and component performance monitoring is not performed. The recommended pump performance parameters are not monitored, and the system contains no heat exchangers. The system contains a number of heating coils as it provides heating to various plant locations. Only select portions of the piping system and heater coils are included in License Renewal scope for pressure integrity only. Some of the heating coils are visually inspected for leaks on a periodic basis. Based on plant operating experience, chemistry control and inspection practices to date of the piping and heating coils have been effective in minimizing the impacts of corrosion and system leakage. As an enhancement to the program, a one time inspection will be performed to monitor the effects of corrosion in select portions of the system within the scope of License Renewal.

In addition to chemistry checks and coolant additions as needed, periodic non-chemical monitoring techniques are used to evaluate performance of the closed cooling loop used for the #14 Air Compressor. Ethylene glycol is used for the heat transfer medium with a radiator and fan for heat rejection. Though the heat transfer function is not in scope for License Renewal, many of the same periodic monitoring techniques can be used to detect leakage or performance degradation that may ultimately impact the License Renewal pressure boundary function. In addition to a local low coolant flow alarm, a number of parameters are monitored and logged on a routine basis including coolant pump suction and discharge pressure, surge tank coolant and oil levels, and various coolant and compressor temperatures and pressures (i.e., compressor oil pressure and temperature, compressor air inlet and outlet temperature, intercooler pressure, compressor coolant inlet and outlet temperature, and aftercooler coolant temperature). As part of periodic compressor maintenance activities, visual inspections of the intercooler, aftercooler, oil cooler, and cooling unit are performed to identify leaks or corrosion. Depending on performance trends, the coolant (internal) side of the various coolers may require inspection and cleaning. Reduced heat transfer performance (from temperature monitoring results) can also be indicative of internal corrosion.

Audit Question No.: B2.1.13-14

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: 4. Exception 4 states that some of the acceptance criteria ranges for monitored chemistry parameters are based on vendor recommendations and plant operating experience, and are not identical to the typical ranges specified by EPRI guidelines. Which acceptance criteria ranges are different, and to what extent? What was the basis for changing these acceptance criteria?

Date Received: 7/20/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Both EPRI TR-107396 and 1007820 specify normal operating ranges and action levels for chemical control parameters. Diagnostic parameters are also specified but action levels and ranges are not included, typically these parameters are used on a trend basis. As noted in the LRA, many of the chemical ranges specified for Monticello are based on ranges identical to or more restrictive than EPRI guidelines. Others are based on vendor recommendations and plant experience. Specific to the four closed-cycle cooling water systems, parameter ranges recommended by EPRI and the corresponding ranges used at Monticello are:

(1) For the chromate based RBC System (which also serves the RHR, REC, and CRD coolers):

· Chromate - Chromate is monitored to a range of 500 to 1800 ppm (not 150 to 300 ppm as recommended by EPRI). As noted in EPRI TR-107396 and 1007820, this may have an impact on pump seal integrity. The RBC pump seals are consumables and impacts to system pressure integrity have not been noted. A new design seal was installed that is replaced on a periodic basis that appears to effectively address any leakage concerns. (Also see response to RAI B2.1.13-01 for further details)
· pH - pH is monitored to a more restrictive range of 9.0 to 9.7, versus the EPRI TR-107396 range of 8.5 to 10.5 and EPRI 1007820 range of 8.0 to 11.0.
· Chloride - Chloride is not monitored in the RBC System. Chloride is monitored in the makeup demineralized water source which provides makeup to the RBC System. Chloride limits for demineralized water have a limit of 10 ppb, which is substantively lower than the limit of 10 ppm established by EPRI.

(2) For the cooling loops of the DGN System:

· Nitrite - The chemical range for nitrite is identical to EPRI TR-107396 (500 to 1,000 ppm) and more restrictive than EPRI 1007820 (50 to 1,500 ppm).
· pH - The range for pH is 9.0 to 10.7, which is more restrictive than the range of 8.5 to 11.0 in EPRI 1007820 and close to the range of 8.5 to 10.5 specified in EPRI TR-107396.
· Tolyltriazole - The specified range is 10 to 40 ppm (not 5 to 30 ppm as in EPRI TR-107396 and more restrictive than 5 to 100 ppm as in EPRI 1007820). No adverse impacts for slightly higher ranges for tolytriazole were noted in EPRI TR-107396.
· Chloride - Chloride is not monitored in the cooling loops of the DGN System. Chloride is monitored in the makeup demineralized water source which provides makeup to the cooling loops. Chloride limits for demineralized water have a limit of 10 ppb, which is substantively lower than the limit of 10 ppm established by EPRI

(3) For the piping and heating coils of the HTV System:

· For the piping and heating coils of the HTV System, chemical ranges are monitored in accordance with vendor recommendations and plant experience and are not specified by EPRI TR-107396 or EPRI 1007820. These include conductivity, pH, phosphate, sulfites, and total gamma activity and are specified by plant procedure.

(4) For the closed cooling loop used on the #14 Air Compressor of the AIR System:

· Glycol % Volume - Both EPRI TR-107396 and 1007820 recommend the glycol percent volume remain above 30% to avoid becoming a nutrient for microbiological growth. Further, EPRI 1007820 recommends the level remain below 60%. The concentration at Monticello is maintained at approximately 50%, which is within the range specified by EPRI.

· pH - A specific range for pH is not specified by plant procedure. However, procedures do require routine sampling and measurement of pH. Further, pH is maintained basic and is within the range specified by EPRI 1007820 of 7.5 to 11.0.

Final Response: Both EPRI TR-107396 and 1007820 specify normal operating ranges and action levels for chemical control parameters. Diagnostic parameters are also specified but action levels and ranges are not included, typically these parameters are used on a trend basis. As noted in the LRA, many of the chemical ranges specified for Monticello are based on ranges identical to or more restrictive than EPRI guidelines. Others are based on vendor recommendations and plant experience. Specific to the four closed-cycle cooling water systems, parameter ranges recommended by EPRI and the corresponding ranges used at Monticello are:

(1) For the chromate based RBC System (which also serves the RHR, REC, and CRD coolers):

· Chromate - Chromate is monitored to a range of 500 to 1800 ppm (not 150 to 300 ppm as recommended by EPRI). As noted in EPRI TR-107396 and 1007820, this may have an impact on pump seal integrity. The RBC pump seals are consumables and impacts to system pressure integrity have not been noted. A new design seal was installed that is replaced on a periodic basis that appears to effectively address any leakage concerns. (Also see response to RAI B2.1.13-01 for further details)
· pH - pH is monitored to a more restrictive range of 9.0 to 9.7, versus the EPRI TR-107396 range of 8.5 to 10.5 and EPRI 1007820 range of 8.0 to 11.0.
· Chloride - Chloride is not monitored in the RBC System. Chloride is monitored in the makeup demineralized water source which provides makeup to the RBC System. Chloride limits for demineralized water have a limit of 10 ppb, which is substantively lower than the limit of 10 ppm established by EPRI.

(2) For the cooling loops of the DGN System:

· Nitrite - The chemical range for nitrite is identical to EPRI TR-107396 (500 to 1,000 ppm) and more restrictive than EPRI 1007820 (50 to 1,500 ppm).
· pH - The range for pH is 9.0 to 10.7, which is more restrictive than the range of 8.5 to 11.0 in EPRI 1007820 and close to the range of 8.5 to 10.5 specified in EPRI TR-107396.
· Tolyltriazole - The specified range is 10 to 40 ppm (not 5 to 30 ppm as in EPRI TR-107396 and more restrictive than 5 to 100 ppm as in EPRI 1007820). No adverse impacts for slightly higher ranges for tolytriazole were noted in EPRI TR-107396.
· Chloride - Chloride is not monitored in the cooling loops of the DGN System. Chloride is monitored in the makeup demineralized water source which provides makeup to the cooling loops. Chloride limits for demineralized water have a limit of 10 ppb, which is substantively lower than the limit of 10 ppm established by EPRI

(3) For the piping and heating coils of the HTV System:

· For the piping and heating coils of the HTV System, chemical ranges are monitored in accordance with vendor recommendations and plant experience and are not specified by EPRI TR-107396 or EPRI 1007820. These include conductivity, pH, phosphate, sulfites, and total gamma activity and are specified by plant procedure.

(4) For the closed cooling loop used on the #14 Air Compressor of the AIR System:

· Glycol % Volume - Both EPRI TR-107396 and 1007820 recommend the glycol percent volume remain above 30% to avoid becoming a nutrient for microbiological growth. Further, EPRI 1007820 recommends the level remain below 60%. The concentration at Monticello is maintained at approximately 50%, which is within the range specified by EPRI.
· pH - A specific range for pH is not specified by plant procedure. However, procedures do require routine sampling and measurement of pH. Further, pH is maintained basic and is within the range specified by EPRI 1007820 of 7.5 to 11.0.

Audit Question No.: B2.1.14-01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question: 1. Program description states "Compressed Air Monitoring Program consists of inspection, monitoring, and testing of the Instrument and Service Air System". Does the program include preventive monitoring or corrective actions?

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Program Basis Document PBD/AMP-011, Compressed Air Monitoring Program, Section 3.1, B, addresses this issue. The Instrument and Service Air System procedures include visual inspections for corrosion during system walk downs. The preventive maintenance procedures for the compressors (4160-01-PM, Instrument Air System - 11 Air Compressor K-1A, 4160-02-PM, Instrument Air System - 14 Air Compressor K-1D, and 4160-03-PM, Instrument Air System - 13 Air Compressor K-1C) require that the following associated equipment be inspected for corrosion (varies according to compressor model):

- compressor
- intercooler and aftercooler (enclosed in housing)
- air receiver
- aftercooler (external to compressor)
- cooling water lines
- air lines for control and instrument operation
- oil cooler
- cooling unit
- main air lines
- instruments

The preventive maintenance procedure for the air dryers, 4161-PM, Instrument Air System Air Dryers (S-4 and S-75), requires that the following parts of the dryer and filter be inspected for corrosion:

- pipes, valves, tanks, and all other components
- pilot filter cartridge
- prefilter cartridge
- afterfilter cartridge

Engineering Work Instruction (EWI)-01.04.06, Conduct of System Engineering, states that the System Engineer should complete periodic in-plant system walk downs and inspections of accessible portions of the system using the System Walkdown Guidelines. This guideline includes checks for corrosion on structural steel, piping surfaces, pipe supports, pumps, and compressors. Additionally, these guidelines include verifying that there is no evidence of piping pressure boundary degradation.

Procedure 1362, Air Quality Test For the Instrument Air System, contains requirements to test the instrument air for water vapor, oil content, and particulate. These tests manage the presence of unacceptable levels of contaminants and ensure adequate instrument air quality. This procedure requires tests every six months at one of six locations for oil content and particulates. In addition, this procedure will be enhanced to include corrective action requirements if the acceptance limits for the water vapor, oil content, and particulate are not met.

Procedure 4159-PM, Instrument and Service Air Leak Survey, identifies and documents leaks in the Instrument Air, Service Air, and Instrument Nitrogen Systems. Once per cycle, a search for system leaks is performed in various plant areas (both accessible and normally non-accessible) and deficiencies are noted and corrected per normal plant procedures.

This enhanced element is consistent with NUREG-1801, Element 1, Scope of Program.

Corrective actions are accomplished by preparing a Condition Report (CR)/Action Request (AR) which shall be initiated in accordance with the site-specific Corrective Action Program. The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. The staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process and administrative controls.

Final Response: Plant procedures address this issue. The Instrument and Service Air System procedures include visual inspections for corrosion during system walk downs. The preventive maintenance procedures for the compressors require that the following associated equipment be inspected for corrosion (varies according to compressor model):

- compressor
- intercooler and aftercooler (enclosed in housing)
- air receiver
- aftercooler (external to compressor)
- cooling water lines
- air lines for control and instrument operation
- oil cooler
- cooling unit
- main air lines
- instruments

The preventive maintenance procedure for the air dryers requires that the following parts of the dryer and filter be inspected for corrosion:

- pipes, valves, tanks, and all other components
- pilot filter cartridge
- prefilter cartridge
- afterfilter cartridge

Plant procedures state that the System Engineer should complete periodic in-plant system walk downs and inspections of accessible portions of the system using the system walkdown guidelines. These guidelines include checks for corrosion on structural steel, piping surfaces, pipe supports, pumps, and compressors. Additionally, these guidelines include verifying that there is no evidence of piping pressure boundary degradation.

Plant procedures contains requirements to test the instrument air for water vapor, oil content, and particulate. These tests manage the presence of unacceptable levels of contaminants and ensure adequate instrument air quality. This procedure requires tests every six months at one of six locations for oil content and particulates. In addition, this procedure will be enhanced to include corrective action requirements if the acceptance limits for the water vapor, oil content, and particulate are not met.

Plant procedures identify and document leaks in the Instrument Air, Service Air, and Instrument Nitrogen Systems. Once per cycle, a search for system leaks is performed in various plant areas (both accessible and normally non-accessible) and deficiencies are noted and corrected per normal plant procedures.

This enhanced element is consistent with NUREG-1801, Element 1, Scope of Program.

Corrective actions are accomplished by preparing a Condition Report (CR)/Action Request (AR) which shall be initiated in accordance with the site-specific Corrective Action Program. The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. The staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable in addressing the confirmation process and administrative controls.

Audit Question No.: B2.1.14-02

Source: **AMP Audit** **Status:** **Sufficient per NRC** **Author:** **Lintz** **MNGP Owner:** **Bill Roman** **Discipline:** **Mechanical**

Question: 2. Scope of program. GALL recommends frequent leak testing of valves, piping, and other system components, especially those made of carbon steel, and a preventive maintenance program to check air quality at several locations in the system. The LRA does not address these activities. What actions are performed in lieu of them?

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: See response to Draft RAI B2.1.14-01.

Final Response: See response to AMP audit question B2.1.14-01.

Audit Question No.: B2.1.14-03

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question: 3. Preventive actions. GALL recommends that testing and inspection requirements are prepared from consideration of manufacturer's recommendations for individual components and guidelines based on ASME OM-S/G-1998, Part 17; ISA-S7.0.01-1996; EPRI NP-7079; and EPRI TR-108147. The LRA does not address on what these requirements are based. Please identify the basis for MNGP testing and inspection requirements.

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: MNGP's Instrument and Service Air System testing and inspection plans ensure that the air meets specified operability requirements. As discussed above in response to Draft RAI B2.1.14-01, various plant procedures control testing and inspection of the air system.

This MNGP AMP does not refer to the NUREG-1801 industry documents as part of the MNGP aging management implementing procedures. Procedure 1362, Air Quality Test For the Instrument Air System, contains requirements to test the instrument air for water vapor, oil content, and particulate. It is based on Specification ANSI/ISA S7.3-1975, Quality Standard for Instrument Air. This resulted from NRC Commitment M89060A made in response to Generic Letter 88-14, Instrument Air Supply Problems Affecting Safety-Related Equipment which is also a basis for Procedure 1362.

Procedure 1335, Air Compressor Weekly Checks, verifies the operability of all three Instrument and Service Air System compressors. It provides instruction for the weekly and monthly surveillances.

As discussed in Section 3.1, Scope of Program, the preventive maintenance program, along with other procedures and instructions, addresses issues of corrosion and the presence of oil, water, rust, and other contaminants. Procedure 1362 is the primary guidance for controlling the levels of contaminants and also ensuring required air quality.

This element is consistent with NUREG-1801 Element 2, Preventive Actions.

Final Response: MNGP's Instrument and Service Air System testing and inspection plans ensure that the air meets specified operability requirements. As discussed above in response to Draft RAI B2.1.14-01, various plant procedures control testing and inspection of the air system.

This MNGP AMP does not refer to the NUREG-1801 industry documents as part of the MNGP aging management implementing procedures. Plant procedures contain requirements to test the instrument air for water vapor, oil content, and particulate. It is based on Specification ANSI/ISA S7.3- 1975, Quality Standard for Instrument Air. This resulted from NRC Commitment M89060A made in response to Generic Letter 88-14, Instrument Air Supply Problems Affecting Safety-Related Equipment which is also a basis for plant procedures.

Plant procedures verify the operability of all three Instrument and Service Air System compressors. They provide instruction for the weekly and monthly surveillances.

The preventive maintenance program, along with other procedures and instructions, addresses issues of corrosion and the presence of oil, water, rust, and other contaminants. Plant procedures control the levels of contaminants and also ensure required air quality.

This element is consistent with NUREG-1801 Element 2, Preventive Actions.

Audit Question No.: B2.1.14-04

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question: 4. Parameters monitored or inspected states "the MNGP Compressed Air Monitoring Program procedures provide an equivalent level of guidance to that provided in NUREG-1801 to verify proper air quality and preventative maintenance to ensure that the intended function of the air system is maintained". How was this equivalent level determined?

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: See response to Draft RAI B2.1.14-03.

Final Response: See response to AMP audit question B2.1.14-03.

Audit Question No.: B2.1.14-05

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question: 5. Detection of aging effects. MNGP takes exception to the guidelines recommended in GALL, stating "This is acceptable because the MNGP Compressed Air Monitoring Program procedures provide an equivalent level of guidance to that provided in NUREG-1801 to ensure timely detection of degradation of the compressed air system function". How was this determination made? How is degradation of piping and equipment detected? How are unacceptable leakage rates determined? How is system or equipment failure detected?

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: MNGP procedures and instructions related to compressed air systems do not explicitly incorporate EPRI NP-7079, EPRI TR-108147, and ASME OM-S/G-1998, Part 17.

As discussed in the Program Basis Document PBD/AMP-011, Compressed Air Monitoring Program, Section 3.1, B, Scope of Program (see response to Draft RAI B2.1.14-01), the preventive maintenance program, along with other procedures and instructions, address issues of corrosion and contamination, thus helping to ensure timely detection of system function degradation.

Procedure 1362 is the primary guidance for controlling the levels of contaminants and also ensuring required air quality. This procedure is based upon the following:
- NRC Generic Letter GL 88-14, Instrument Air Supply System Problems Affecting Safety Related Equipment.
- Specification ANSI/ISA S7.3, Quality Standard for Instrument Air.
- Specification ANSI Z86.1-1973, Pamphlet G-71, Commodity Specification for Air and Drager Operating Instruction Table 4.7.1.
- EPRI Report TR103595, Report of the Instrument Air Working Group, dated 4/94

As previously discussed in Scope of Program, various MNGP procedures and instructions examine system corrosion and leakage. The compressors and air dryers are inspected and maintained by preventive maintenance procedures. Procedure 1335, Air Compressor Weekly Checks, verifies the operability of all three Instrument and Service Air Compressors during weekly and monthly
surveillances.

MNGP's program is based on the guidance provided in ANSI/ISA-S7.3-1975, ANSI/ISA-Z86.1-1973, EPRI TR-103595 and Generic Letter 88-14 which is augmented by previous NRC Information Notices (IN) 81-38, IN 87-28, IN 87-28 Supplement 1, and by the Institute of Nuclear Power Operations Significant Operating Experience Report (INPO SOER) 88-01.

MNGP takes exception to ANSI/ISA-S7.0.01-1996 because MNGP uses ANSI/ISA-S7.3-1975. In the "Safety Evaluation Report - Related to the License Renewal of the Dresden Nuclear Power Station, Units 2 and 3, and the Quad Cities Nuclear Power Station, Units 1 and 2" (Accession Number ML042050507), the NRC found use of ANSI/ISA-S7.3-1975 acceptable because it is more conservative than ANSI/ISA-S7.0.01-1996.

MNGP takes exception to ASME OM-S/G-1998, Part 17 as specified in NUREG-1801, XI.M24. In the "Safety Evaluation Report - Related to the License Renewal of the Dresden Nuclear Power Station, Units 2 and 3, and the Quad Cities Nuclear Power Station, Units 1 and 2" (Accession Number ML042050507), the NRC found this acceptable because the instrument air system compressors, receivers, filters, and dryers are not within the scope of license renewal, therefore, the instrument air systems do not require performance testing for aging management.

This is acceptable since the MNGP Compressed Air Monitoring Program procedures provide an equivalent level of guidance to that provided in NUREG-1801 to ensure timely detection of degradation of the compressed air system function.

Final Response: MNGP procedures and instructions related to compressed air systems do not explicitly incorporate EPRI NP-7079, EPRI TR-108147, and ASME OM-S/G-1998, Part 17.

As discussed in plant procedures (see response to Draft RAI B2.1.14-01), the preventive maintenance program, along with other procedures and instructions, address issues

of corrosion and contamination, thus helping to ensure timely detection of system function degradation.

Plant procedures control the levels of contaminants and also ensuring required air quality. This procedure is based upon the following:
- NRC Generic Letter GL 88-14, Instrument Air Supply System Problems Affecting Safety Related Equipment.
- Specification ANSI/ISA S7.3, Quality Standard for Instrument Air.
- Specification ANSI Z86.1-1973, Pamphlet G-71, Commodity Specification for Air and Drager Operating Instruction Table 4.7.1.
- EPRI Report TR103595, Report of the Instrument Air Working Group, dated 4/94

As previously discussed, MNGP procedures and instructions examine system corrosion and leakage. The compressors and air dryers are inspected and maintained by preventive maintenance procedures. Plant procedures verify the operability of all three Instrument and Service Air Compressors during weekly and monthly surveillances.

MNGP's program is based on the guidance provided in ANSI/ISA-S7.3-1975, ANSI/ISA-Z86.1-1973, EPRI TR-103595 and Generic Letter 88-14 which is augmented by previous NRC Information Notices (IN) 81-38, IN 87-28, IN 87-28 Supplement 1, and by the Institute of Nuclear Power Operations Significant Operating Experience Report (INPO SOER) 88-01.

MNGP takes exception to ANSI/ISA-S7.0.01-1996 because MNGP uses ANSI/ISA-S7.3-1975. In the "Safety Evaluation Report - Related to the License Renewal of the Dresden Nuclear Power Station, Units 2 and 3, and the Quad Cities Nuclear Power Station, Units 1 and 2" (Accession Number ML042050507), the NRC found use of ANSI/ISA-S7.3-1975 acceptable because it is more conservative than ANSI/ISA-S7.0.01-1996.

MNGP takes exception to ASME OM-S/G-1998, Part 17 as specified in NUREG-1801, XI.M24. In the "Safety Evaluation Report - Related to the License Renewal of the Dresden Nuclear Power Station, Units 2 and 3, and the Quad Cities Nuclear Power Station, Units 1 and 2" (Accession Number ML042050507), the NRC found this acceptable because the instrument air system compressors, receivers, filters, and dryers are not within the scope of license renewal, therefore, the instrument air systems do not require performance testing for aging management.

This is acceptable since the MNGP procedures provide an equivalent level of guidance to that provided in NUREG-1801 to ensure timely detection of degradation of the compressed air system function.

Audit Question No.: B2.1.14-06

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question: 6. Monitoring and trending. GALL recommends visual inspection and periodic system and component tests, including leak rate tests on the system and on individual items of equipment. The LRA identifies periodic inspection, but does not address component tests or leak rate tests. Are such tests performed to verify proper component operation? Is test data analyzed and compared to provide for timely detection of aging effects?

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Program Basis Document PBD/AMP-011, Compressed Air Monitoring Program, Section 3.5, B , addresses this issue. MNGP procedures, instructions, and System Walkdown Guidelines mentioned in Section 3.1, Scope of Program (see response to Draft RAI B2.1.14-01), monitor the effects of corrosion. This is accomplished by visual inspections during walk downs of the system and individual items of equipment. Preventive maintenance procedures require periodic inspection of the system piping, compressors and air dryers. The presence of contaminants is monitored by the performance of Procedure 1362.

Once per cycle the Instrument Air, Service Air, and Instrument Nitrogen Systems are examined for system leaks per 4159-PM. Other procedures require checks for leakage, as described in Section 3.1, Scope of Program.

This element is consistent with NUREG-1801, Element 5, Monitoring and Trending.

Final Response: Plant procedures address this issue. MNGP procedures, instructions, and system walkdown guidelines (see also response to Draft RAI B2.1.14-01), monitor the effects of corrosion. This is accomplished by visual inspections during walk downs of the system and individual items of equipment. Preventive maintenance procedures require periodic inspection of the system piping, compressors and air dryers. The presence of contaminants is monitored by the performance of plant procedures.

Once per cycle the Instrument Air, Service Air, and Instrument Nitrogen Systems are examined for system leaks. Other procedures require checks for leakage.

This element is consistent with NUREG-1801, Element 5, Monitoring and Trending.

Audit Question No.: B2.1.14-07

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question: 7. Acceptance criteria states "Other Instrument and Service Air System inspection procedures require visual inspection and criteria for corrective action". This implies that these procedures currently lack acceptance criteria. Is this the case? Please explain.

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Program Basis Document PBD/AMP-011, Compressed Air Monitoring Program, Section 3.6, B, addresses this issue. The following procedures contain inspection, preventive maintenance activities and acceptance criteria to ensure the associated components or equipment are capable of performing their intended function.

- 4160-01-PM, 4160-02-PM, and 4160-03-PM: These procedures are the preventive maintenance procedures for the three instrument air compressors. Although the procedures are very similar, there are slight differences in the tests and inspections that they require. The majority of the requirements are visual inspections, cleaning, and lubrication. Acceptance criteria are based on vendor specifications and are provided for the relevant steps.

- 4161-PM, Instrument Air System Air Dryers (S-4 and S-75). This procedure requires that the pipes, valves, tanks, and all other components of the dryer and filter be inspected for cleanliness, corrosion and leaks. Vents and drains are to be inspected for obstructions. The pilot filter, the prefilter cartridges, and afterfilter cartridges are to be inspected for excessive corrosion, cracked or damaged end seals. Preventive maintenance and acceptance criteria are based on vendor recommendations.

- Procedure 1362, Air Quality Test For the Instrument Air System. This procedure provides acceptance requirements for the water vapor, oil content, and particulate tests based on ANSI/ISA S7.3, Quality Standard for Instrument Air, and ANSI Z86.1-1973, Pamphlet G-71, Commodity Specification for Air and Drager Operating Instruction, Table 4.7.1.

This element is consistent with NUREG-1801, Element 6, Acceptance Criteria.

Final Response: Plant procedures address this issue and contain inspection, preventive maintenance activities and acceptance criteria to ensure the associated components or equipment are capable of performing their intended function.

- Preventive maintenance procedures for the three instrument air compressors. Although the procedures are very similar, there are slight differences in the tests and inspections that they require. The majority of the requirements are visual inspections, cleaning, and lubrication. Acceptance criteria are based on vendor specifications and are provided for the relevant steps.

- Plant procedures require that the pipes, valves, tanks, and all other components of the dryer and filter be inspected for cleanliness, corrosion and leaks. Vents and drains are to be inspected for obstructions. The pilot filter, the prefilter cartridges, and afterfilter cartridges are to be inspected for excessive corrosion, cracked or damaged end seals. Preventive maintenance and acceptance criteria are based on vendor recommendations.

- Plant procedures provide acceptance requirements for the water vapor, oil content, and particulate tests based on ANSI/ISA S7.3, Quality Standard for Instrument Air, and ANSI Z86.1-1973, Pamphlet G-71, Commodity Specification for Air and Drager Operating Instruction, Table 4.7.1.

This element is consistent with NUREG-1801, Element 6, Acceptance Criteria.

Audit Question No.: B2.1.24-01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question: 1. Scope of Program states "The Service Water and Fire Protection Inspection Program monitors (sic) aging effects applicable to piping" and "The MNGP Open-Cycle Cooling Water System manages the aging effects for targeted components of the following systems or structures: Circulating Water, Heating & Ventilation, Core Spray System, Residual Heat Removal, Emergency Diesel Generators, Reactor Building, Closed Cooling Water, Emergency Filtration Train Service, Seal Water, Emergency Service Water, and Turbine Generator". Several of these systems would not appear to be in either the fire protection or the service water systems. Explain.

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Program Basis Document PBD/AMP-007, Open-Cycle Cooling Water System Program, Section 3.1, B, addresses this issue. The "The Service Water and Fire Protection Inspection Program" (these two systems have previously been addressed in the same procedure) addresses the Service Water System as part of the OCCW Program and the Open-Cycle Cooling Water System addresses the remainder of the systems. The Fire Protection System (water suppression) is addressed in the Fire Water Program. No structures are included in the OCCW Program. However, the proper name for these systems as stated in the LRA is as follows:

- Circulating Water System
- Core Spray System
- Emergency Diesel Generators - OCCW
- Emergency Filtration Train
- Emergency Service Water Systems
- Heating and Ventilation
- Residual Heat Removal System
- Reactor Building Closed Cooling Water System
- Service and Seal Water
- Turbine Generator System

All of the above systems are serviced and addressed by the OCCW Program.

Final Response: The program basis document addresses this issue. A plant program addresses the Service Water System as part of the OCCW Program and the Open-Cycle Cooling Water System addresses the remainder of the systems. The Fire Protection System (water suppression) is addressed in the Fire Water Program. No structures are included in the OCCW Program. However, the proper name for these systems as stated in the LRA is as follows:

- Circulating Water System
- Core Spray System
- Emergency Diesel Generators - OCCW
- Emergency Filtration Train
- Emergency Service Water Systems
- Heating and Ventilation
- Residual Heat Removal System
- Reactor Building Closed Cooling Water System
- Service and Seal Water
- Turbine Generator System

All of the above systems are serviced and addressed by the OCCW Program.

Audit Question No.: B2.1.24-02

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question: 2. Preventive actions states "MNGP has a prevention and inspection monitoring program for OCCW piping and components that is based on NRC GL 89-13". Please clarify whether MNGP performs any surveillance, control techniques, or preventive maintenance to reduce flow blockage.

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Program Basis Document PBD/AMP-007, Open-Cycle Cooling Water System Program, Section 3.2, B, addresses this issue. Visual inspections and NDE monitoring are performed when applicable. Control or preventive measures include:
- Biocide injection: MNGP has a Biocide Injection System to control zebra mussels and MIC (Ops Man B.8.01.5-01). Per EWI-08.22.01, §6.1.4 B, "sodium bromide and sodium hypochlorite are injected into the intake bay and
service water header to control the growth of organisms."
- Silt dispersant injection: Per EWI-08.22.01, §6.1.4 B, "a silt dispersant is injected into the service water header to inhibit formation of mineral scales, disperse silt, suspended solids, and other foulants, and to maintain
cleaner heat transfer surfaces."
- System flushing: Per EWI-08.22.01, §6.1.4D, "the RHR, RHRSW and Core Spray motor coolers are flushed quarterly to detect fouling or blockage in the service water lines. Additionally, each loop of the EDG/ESW system is operated monthly during testing of the diesels. Test results are trended and actions taken, if required."

Final Response: Plant procedures address this issue. Visual inspections and NDE monitoring are performed when applicable. Control or preventive measures include:
1.Biocide injection: MNGP has a Biocide Injection System to control zebra mussels and MIC, sodium bromide and sodium hypochlorite are injected into the intake bay and service water header to control the growth of organisms.
2.Silt dispersant injection: MNGP injects a silt dispersant into the service water header to inhibit formation of mineral scales, disperse silt, suspended solids, and other foulants, and to maintain cleaner heat transfer surfaces.
3.System flushing: At MNGP the RHR, RHRSW and Core Spray motor coolers are flushed quarterly to detect fouling or blockage in the service water lines. Additionally, each loop of the EDG/ESW system is operated monthly during testing of the diesels. Test results are trended and actions taken, if required.

Audit Question No.: B2.1.24-03

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question: 3. Did the initial inspection identify the existence of any local macroscopic biological fouling species, e.g., mussels, clams and associated larvae?

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: NRC Service Water System Operational Performance Inspection (50-263/92010) dated September 30, 1992, assessed the planned or completed actions for MNGP in response to GL 89-13. The results of this inspection with regard to biological fouling is as follows:

The procedures inspected and documented sediment build-up, corrosion, and mussels or clams. There were no indications of zebra mussels or Asiatic clams in the intake structure; although, sediment buildup required dredging operations. Sampling of river water for mussels and clams was accomplished by placing concrete blocks in the intake bay during spawning season to periodically check for their presence in the river. There has been no evidence of mussels or clams during the last 2 years.

To minimize the buildup of microbiological organisms, hypochlorite/bromine solutions were injected daily into the nonsafety related SWS and the service bays. The bays provided suction to the three safety related SWS and fire protection system. This injection ensured that the safety related system piping contained treated water while in the standby mode. The amount of chemicals injected was based on daily water analysis by the chemistry department. A silt dispersion agent was also injected continuously into the nonsafety related SWS. Based on the lack of zebra mussels and Asiatic clams in the river, the licensee's actions for biocide injection appeared to be aggressive and responsive to the GL request.

Final Response: NRC Service Water System Operational Performance Inspection assessed the planned or completed actions for MNGP in response to GL 89-13. The results of this inspection with regard to biological fouling is as follows:

The procedures inspected and documented sediment build-up, corrosion, and mussels or clams. There were no indications of zebra mussels or Asiatic clams in the intake structure; although, sediment buildup required dredging operations. Sampling of river water for mussels and clams was accomplished by placing concrete blocks in the intake bay during spawning season to periodically check for their presence in the river. There has been no evidence of mussels or clams during the last 2 years.

To minimize the buildup of microbiological organisms, hypochlorite/bromine solutions were injected daily into the nonsafety related SWS and the service bays. The bays provided suction to the three safety related SWS and fire protection system. This injection ensured that the safety related system piping contained treated water while in the standby mode. The amount of chemicals injected was based on daily water analysis by the chemistry department. A silt dispersion agent was also injected continuously into the nonsafety related SWS. Based on the lack of zebra mussels and Asiatic clams in the river, the licensee's actions for biocide injection appeared to be aggressive and responsive to the GL request.

Audit Question No.: B2.1.24-04

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question: 4. GALL, parameters monitored and inspected recommends: "The program ensures (a) removal of accumulations of biofouling agents, corrosion products, and silt, and detection of defective protective coatings and corroded OCCW system piping and components that could adversely affect performance of their intended safety functions". The MNGP does not address this. Explain.

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Program Basis Document PBD/AMP-007, Open-Cycle Cooling Water System Program, Section 3.3, B, addresses this issue. Per Engineering Work Instruction EWI-08.22.01, Generic Letter 89-013, parameters monitored or inspected include the following:

- Service water bays are inspected for sediment buildup, corrosion, and other types of macro fouling such as Asiatic clams and zebra mussels.
- Locally indicating pressure gauges throughout the service water systems allow detection of flow degradation due to blockage of piping or heat exchangers.
- RHR, RHRSW, and Core Spray motor coolers are flushed quarterly to detect fouling or blockage in these service water lines.
- The work control process requires that any time a safety related service water system is opened, an inspection will be performed. Visual inspections for excessive corrosion, biofouling, erosion, and silt buildup are specified and performed.

Protective coatings or linings are not used in the MNGP service water piping and components.

Final Response: Plant procedures address this issue. The parameters monitored or inspected include the following:

- Service water bays are inspected for sediment buildup, corrosion, and other types of macro fouling such as Asiatic clams and zebra mussels.
- Locally indicating pressure gauges throughout the service water systems allow detection of flow degradation due to blockage of piping or heat exchangers.
- RHR, RHRSW, and Core Spray motor coolers are flushed quarterly to detect fouling or blockage in these service water lines.
- The work control process requires that any time a safety related service water system is opened, an inspection will be performed. Visual inspections for excessive corrosion, biofouling, erosion, and silt buildup are specified and performed.

Protective coatings or linings are not used in the MNGP service water piping and components.

Audit Question No.: B2.1.24-05

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question: 5. Detection of aging effects. How does MNGP verify heat exchanger heat transfer capability? How does MNGP inspection and maintenance ensure that corrosion, erosion, silting, and biofouling will not degrade system performance or identify corroded piping and components? If MNGP performs heat exchanger testing under off-design conditions, describe what testing is performed and how are results analyzed.

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Program Basis Document PBD/AMP-007, Open-Cycle Cooling Water System Program, Section 3.4, B, addresses this issue. The MNGP programs include inspections for biofouling, corrosion, erosion or heat exchanger performance degradation.

Visual inspection is one of several inspection methods used as part of the OCCW program. Fleet Procedure FP-PE-SW- 01, Service Water and Fire Protection Inspection Program, Section 5.4.1, states, "Visual inspections of disassembled
piping components are an important part of the program. As work for repairs, replacements, or general maintenance is performed, system observations shall be made."

Additionally, EWI-08.22.01 states that the work control process and the Operations Manual sections for the service water systems require visual inspections whenever any safety related service water systems are opened. Inspection guidance is provided in Form 3590, "Service Water Component Inspection". The systems are inspected for biofouling, corrosion, silting, and other foreign material. In response to GL 89-13, MNGP has made commitments that are listed in this EWI to visually inspect and/or test the heat transfer capability of all safety related heat exchangers cooled by open-cycle cooling water.

Plant piping susceptible to erosion or corrosion is inspected using ultrasonic testing (UT) methods. The MNGP EWIs and the Fleet procedures listed in Table 7.3 provide guidance for these inspections. This is a GL 89-13 commitment and the results are used to determine corrosion rates, the extent of the biofouling or wall thinning, and any required corrective actions.

The Heat Exchanger Condition Assessment Program (EWI- 08.22.02) describes eddy current testing of plant heat exchangers (both safety and non-safety related) as an effective method to monitor heat exchanger performance and possible degradation. The test results are used for both trending and repair evaluations for tube plugging issues.

This EWI provides a program of preventive maintenance (PM) tasks for plant heat exchangers as a method for determining the causes and mechanisms that lead to degradation and failure.

As part of MNGP's GL 89-13 commitments (Item 2), a test program has been established to verify the heat transfer capability of selected safety related heat exchangers cooled by service water. This includes inspection, cleaning, monitoring, and testing of applicable heat exchangers, and resolution of any tube plugging issues. The tests determine any degradation of heat transfer capability, which usually results from fouling caused by silt, sediment, or scale.

Refer to EWI-08.22.01 for a listing of safety related heat exchangers and coolers in this program.

The service water systems have pressure gauges to allow detection of flow degradation due to blockage of piping or heat exchangers and take timely corrective action prior to loss of intended function.

This element is consistent with NUREG-1801, Element 4, Detection of Aging Effects.

Final Response: Plant procedures address this issue. The MNGP programs include inspections for biofouling, corrosion, erosion or heat exchanger performance degradation.

Visual inspection is one of several inspection methods used as part of the OCCW program. Plant procedures state that visual inspections of disassembled piping components are an important part of the program. As work for repairs, replacements, or general maintenance is performed, system observations shall be made.

Additionally, plant procedures also state that the work control process and the operations manual sections for the service water systems require visual inspections whenever any safety related service water systems are opened. Inspection guidance is also provided for service water components. The systems are inspected for biofouling, corrosion, silting, and other foreign material. In response to GL 89-13, MNGP has made commitments that are listed in this plant procedures to visually inspect and/or test the heat transfer capability of all safety related heat exchangers cooled by open-cycle cooling water.

Plant piping susceptible to erosion or corrosion is inspected using ultrasonic testing (UT) methods. This is a GL 89-13 commitment and the results are used to determine corrosion rates, the extent of the biofouling or wall thinning, and any required corrective actions.

Plant programs describe eddy current testing of plant heat exchangers (both safety and non-safety related) as an effective method to monitor heat exchanger performance and possible degradation. The test results are used for both trending and repair evaluations for tube plugging issues.

Plant programs provide a program of preventive maintenance (PM) tasks for plant heat exchangers as a method for determining the causes and mechanisms that lead to degradation and failure.

As part of MNGP's GL 89-13 commitments, a test program has been established to verify the heat transfer capability of selected safety related heat exchangers cooled by service water. This includes inspection, cleaning, monitoring, and testing of applicable heat exchangers, and resolution of any tube plugging issues. The tests determine any degradation of heat transfer capability, which usually results from fouling caused by silt, sediment, or scale.

Plant procedures provide a listing of safety related heat exchangers and coolers in this program.

The service water systems have pressure gauges to allow detection of flow degradation due to blockage of piping or heat exchangers and take timely corrective action prior to loss of intended function.

This element is consistent with NUREG-1801, Element 4, Detection of Aging Effects.

Audit Question No.: B2.1.24-06

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question: 6. Acceptance criteria states: "NDE inspection techniques contain acceptance criteria and are used to determine the adequacy of the piping or heat exchangers." How do the acceptance criteria determine the absence of flow blockage?

Date Received: 6/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Program Basis Document PBD/AMP-007, Open-Cycle Cooling Water System Program, Section 3.1, B, addresses this issue. The MNGP Open Cycle Cooling Water program removes or reduces biofouling in OCCW (or Service Water) system as part of the Generic Letter 89-013 Program described in EWI-08.22.01.

The MNGP Heat Exchanger Condition Assessment Program as described in EWI-08.22.02, contains guidance for the selection, inspection, assessment, and maintenance of heat exchangers. Unacceptable inspection results for heat
exchangers are discussed in the guidance on inspection frequency, tube sampling criteria, tube plugging criteria, and eddy current testing.

Other heat exchanger inspection guidance is provided by Forms 3590 and 3802. Form 3590, "Service Water Component Inspection", provides generic instructions for visual inspections of various service water system components for macrofouling, silting, biofouling, or other mechanisms. Form 3802, "Visual Inspection of Heat Exchanger Condition", identifies any unknown degradation or significant changes in degradation of heat exchangers.

EWI-08.22.02 describes the NDE inspection techniques such as visual examinations and UT that are used to determine the adequacy of the heat exchangers. This procedure also describes the eddy current inspection program that utilizes the EPRI Heat Exchanger Risk Assessment Calculator to evaluate allowable tube wall loss as an input for tube plugging decisions. Flaw indications are resolved using the MNGP corrective action process.

These NDE techniques and associated acceptance criteria confirm the absence of flow blockage

This element is consistent with NUREG-1801, Element 6, Acceptance Criteria.

Final Response: Plant procedures address this issue and remove or reduce biofouling in OCCW (or Service Water) system as part of the Generic Letter 89-013.

Plant programs contain guidance for the selection, inspection, assessment, and maintenance of heat exchangers. Unacceptable inspection results for heat exchangers are discussed in the guidance on inspection frequency, tube sampling criteria, tube plugging criteria, and eddy current testing.

Other heat exchanger inspection guidance is provided by plant forms which provide generic instructions for visual inspections of various service water system components for macrofouling, silting, biofouling, or other mechanisms. These forms identify any unknown degradation or significant changes in degradation of heat exchangers.

Plant procedures describe the NDE inspection techniques such as visual examinations and UT that are used to determine the adequacy of the heat exchangers. These procedures also describe the eddy current inspection program that utilizes the EPRI Heat Exchanger Risk Assessment Calculator to evaluate allowable tube wall loss as an input for tube plugging decisions. Flaw indications are resolved using the MNGP corrective action process.

These NDE techniques and associated acceptance criteria confirm the absence of flow blockage

This element is consistent with NUREG-1801, Element 6, Acceptance Criteria.

Audit Question No.: B2.1.28-01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question: 1. The MNGP LRA, B2.1.28, states: "Exceptions to ASME requirements that have been granted by approved Code Cases or relief requests are not considered to be exceptions to NUREG-1801 criteria."

What exceptions apply to B2.1.28? Please list, identify the source, and explain all exceptions.

Date Received: 6/9/2005 Potential Submittal on ☑ Potential LRA Update Required ☑ Assoc LRA Section - Appendix B

Draft Response: See response to RAI# B2.1.26-01.

Final Response: See response to RAI# B2.1.26-01.

Audit Question No.: B2.1.28-02

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question: 2. Please identify the tensile strength of the closure studs and nuts within scope of B2.1.28.

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The 64 reactor pressure vessel head closure studs and nuts are comprised of SA540, Grade B23/24, Class 3. The material specification requires a minimum tensile strength of 145 ksi.

JPP 6/10/05

Final Response: The 64 reactor pressure vessel head closure studs and nuts are comprised of SA540, Grade B23/24, Class 3. The material specification requires a minimum tensile strength of 145 ksi.

Audit Question No.: B2.1.28-03

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question: 3. Does B2.1.28 address loss of material or coolant leakage on the closure studs and nuts within scope?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The Reactor Head Closure Studs AMP manages the reactor closure studs and nuts for crack initiation and growth due to stress corrosion cracking and intergranular stress corrosion cracking exposed to an environment of "Air, Leaking Reactor Coolant Water and/or Steam at 288ºC (550ºF)" in accordance with NUREG-1801, Item IV.A1.1-c. The aging effect "Loss of Material" was not assumed.

JPP 6/10/05

Final Response: The Reactor Head Closure Studs AMP manages the reactor closure studs and nuts for crack initiation and growth due to stress corrosion cracking and intergranular stress corrosion cracking exposed to an environment of "Air, Leaking Reactor Coolant Water and/or Steam at 288ºC (550ºF)" in accordance with NUREG-1801, Item IV.A1.1-c. The aging effect "Loss of Material" was not assumed.

Audit Question No.: B2.1.28-04

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question: 4. Will inspection procedures for the examination of these closure nuts and studs be available during this audit?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Yes. Applicable procedures for the Reactor Head Closure Studs AMP are as follows:

4 AWI-09.04.00 Inservice Inspection Licensee Control Program
4 AWI-07.03.01 Nondestructive Examination
4AWI-09.04.03 ASME Section XI Repair/Replacement Program
Inservice Inspection Examination Plan
EWI-09.04.00 ASME Section XI Inservice Inspection Program
PEI-02.05.01 Visual Examination
PEI-02.08.03 Inservice Inspection Flaw Evaluation
PEI-02.03.06 Ultrasonic Examination of Bolts and Studs to Appendix VIII

JPP 6/10/05

Final Response: Yes. Applicable procedures for the Reactor Head Closure Studs AMP are available

Audit Question No.: B2.1.28-05

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question: 5. Will MNGP Reactor Head Closure Studs Program be available during this audit?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Yes, the Reactor Head Closure Studs AMP is described in MNGP Aging Management Program Basis Document, "Reactor Head Closure Studs", PBD/AMP-034, which will be available for review.

JPP 6/10/05

Final Response: Yes, the Reactor Head Closure Studs AMP is described in MNGP Aging Management Program Basis Document, which will be available for review.

Audit Question No.: B2.1.28-06

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question: 6. What are the applicable MNGP procedures mentioned in B2.1.28, "Acceptance Criteria?" Will these procedures be available during this audit?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: MNGP Procedures - EWI-09.04.00 ASME Section XI Inservice Inspection Program and PEI-02.08.03 Inservice Inspection Flaw Evaluation. These procedures will be available for review during the audit.

JPP 6/10/05

Final Response: The applicable MNGP Procedures will be available for review during the audit.

Audit Question No.: B2.1.28-07

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question: 7. The MNGP LRA, B2.1.28, states that "no cracking, NDE indications or aging effects for the RPV studs" have been detected at MNGP. Has there been absolutely zero results to report, for this program?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Correct. There have been no recorded indications on the ISI examination reports for the RPV studs.

JPP 6/10/05

Final Response: Correct. There have been no recorded indications on the ISI examination reports for the RPV studs.

Audit Question No.: B2.1.28-08

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question: Scope of program identifies specific aging effects for which to examine: SCC, IGSCC, wear, and leakage. The LRA does not mention these.

Date Received: 6/13/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Per NUREG-1801 (A2.1-d), loss of material due to wear is only assumed in PWRs.

On LRA page 3-51, Table 3.1.2-2 Reactor Coolant System - Reactor Pressure Vessel, The Reactor Head Closure Studs AMP manages the closure studs & nuts for crack initiation and growth due to stress corrosion cracking and intergranular stress corrosion cracking in accordance with NUREG-1801, Item IV.A1.1-c.

Final Response: Per NUREG-1801 (A2.1-d), loss of material due to wear is only assumed in PWRs.

On LRA page 3-51, Table 3.1.2-2 Reactor Coolant System - Reactor Pressure Vessel, The Reactor Head Closure Studs AMP manages the closure studs & nuts for crack initiation and growth due to stress corrosion cracking and intergranular stress corrosion cracking in accordance with NUREG-1801, Item IV.A1.1-c.

Audit Question No.: B2.1.28-10

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question: Preventative actions: GALL recommends that stable lubricants be used. The LRA does not specify any lubricants. What lubricants are used on these studs?

Date Received: 6/13/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: A dry film graphite lubricant (Dag 156) is used on the reactor pressure vessel head studs. See MNGP procedure 9262, "Install Reactor Pressure Vessel Head and Stud Nuts and Washers".

Molybdenum disulphide based lubricants (known as a contributor to stress corrosion cracking) are not used in the high strength bolt application at MNGP (i.e, Reactor Pressure Vessel head studs).

Final Response: A dry film graphite lubricant (Dag 156) is used on the reactor pressure vessel head studs.

Molybdenum disulphide based lubricants (known as a contributor to stress corrosion cracking) are not used in the high strength bolt application at MNGP (i.e, Reactor Pressure Vessel head studs).

Audit Question No.: B2.1.28-11

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Lintz **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question: Operating experience: The LRA states that no cracking has been detected. Has any wear been detected?

Date Received: 6/13/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: There have been no recorded indications on the ISI examination reports for the RPV studs.

Final Response: There have been no recorded indications on the ISI examination reports for the RPV studs.

Audit Question No.: B2.1.23-01i

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Merzke **MNGP Owner:** Jim Rootes **Discipline:** Programs

Question: Draft a sampling plan for the One-Time Inspection and have it available for the Aging Management Program (AMP) audit (scheduled for the week of 6/13/2005).

Date Received: 5/18/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - B2.1.23

Draft Response: To be provided to NRC AMP Audit Team on arrival on site.

Final Response:

Audit Question No.: B2.1.20-07

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Messitt **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question: 7.Why has Monticello not found it necessary to sample Fuel oil for biological contaminants, especially when it seems to be a problem in other plants?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: As stated in PBD/AMP-017, "Fuel Oil Chemistry Program", the MNGP fuel oil quality is maintained by monitoring and controlling fuel oil contamination in accordance with the guidelines of the American Society for Testing Materials (ASTM) Standards D 1796, D 2276, D 2709, and D 4057. Exposure to fuel oil contaminants, such as water and microbiological organisms, is minimized by periodic draining or cleaning of tanks and by verifying the quality of new oil before its introduction into the storage tanks.

Samples are taken in accordance with ASTM D 4057 and are shipped to an approved laboratory for analysis, in accordance with the MNGP Quality Assurance (QA) program. Qualified technicians using approved test equipment process the samples and reports are generated and sent back to the plant for review and retention. MNGP procedures include the following ASTM standards:
ASTM D 975 for purchasing of Diesel Fuel Oil
ASTM D 4057 for sampling
ASTM D 6217 for testing for particulates
ASTM D 1796 for testing for water and sediment
ASTM D 287 for testing API gravity

The Emergency Diesel Generator day tanks and base tanks are visually checked monthly for water and sediment. The Diesel Oil Storage Tank (T-44) is sampled monthly for particulate contamination and quarterly to verify the diesel fuel oil is within the acceptable limits for viscosity, water and sediment. The Diesel Oil Storage Tank is drained and inspected if deemed necessary based on the trends indicated by the results of the diesel fuel oil analysis, or as recommended by the System Engineer based on equipment operating experience. Internal tank inspections will identify loss of material due to various aging mechanisms, including general, crevice, galvanic, and pitting corrosion and Microbiologically
Influenced Corrosion (MIC).

The MNGP Fuel Oil Chemistry Program provides reasonable assurance that the aging effect of loss of material caused by various corrosion mechanisms and cracking, including biological contaminants, will be adequately managed. The diesel fuel oil system components that are covered by this program will continue to perform their intended functions for the period of extended operation. The diesel fuel oil monthly and quarterly sampling and trending have confirmed the adequacy of the diesel fuel oil supply. Past tank cleanings and inspections have verified that the condition of the tanks has not degraded.

A review of MNGP condition reports for the diesel fuel oil subsystem tanks that are in the License Renewal scope (Diesel Oil Storage Tank (T-44), the two Emergency Diesel Generator Day Tanks (T-45A and T-45B), the Emergency Diesel Generator Base Tanks), and Diesel Fire Pump Day Tank (t-100) do not show any aging management related issues. A review of plant documentation shows that the subject tanks were cleaned and inspected at various times since initial plant startup.

- The Diesel Oil Storage Tank and the two Emergency Diesel Generator Day Tanks were cleaned in August of 1984, which was the first cleaning since startup. A visual inspection of the tank internals showed that they were in excellent condition, with no leaks, cracks, or significant deterioration observed. (Memo, Gausman to Goranson, "Cleanout of Diesel Oil Tanks, November 15, 1984.

- The Diesel Oil Storage Tank and the two Emergency Diesel Generator Day Tanks were cleaned and inspected during the 1993 refuel outage. In addition, the Emergency Diesel Generator Base Tanks were flushed (no internal inspection was performed because these tanks only have a three inch access opening). The Work Request Authorizations (WRA #'s 92-06184, 92-06189, 92-06192) and associated inspection memos (Foster to B.8.11 Results File, April 12, 1993) were reviewed and showed: The internal surfaces of T-44 were in very good condition, other than some minor internal surface pitting found on the bottom of T-44. No significant corrosion, rust or degradation was found. The internal visual inspection of T-45A and T-45B showed that the internal surfaces were all in excellent condition. No significant corrosion, rust, or pitting was found. All welds and piping connections looked good. Complete NDE wall thickness measurements of the top, sides and bottom were made.

- The only tank cleaned and inspected during the 2003 outage was the Diesel Oil Storage Tank (T-44). Work Order 0202752 stated that the tank was cleaned and NDE inspections for wall thickness and condition were performed and that no problems were found. The MNGP Level III review of the inspection results stated that no repairs were indicated or required. A review of condition reports for the subject tanks and discussion with the former diesel fuel oil system engineer has shown acceptable operation of the system in recent years. This operating experience hasn't identified any problems involving water in the diesel fuel oil, particulate contamination, or biological fouling.

Consequently, MNGP does sample fuel oil for biological contaminants as stated above and operating experience has confirmed the absence of this potential and resultant loss of material due to MIC.

Final Response: As stated in MNGP program basis document for the Fuel Oil Chemistry Program, the MNGP fuel oil quality is maintained by monitoring and controlling fuel oil contamination in accordance with the guidelines of the American Society for Testing Materials (ASTM) Standards D 287, D 975, D 1796, D 4057 and D 6217. Exposure to fuel oil contaminants, such as water and microbiological organisms, is minimized by periodic draining or cleaning of tanks and by verifying the quality of new oil before its introduction into the storage tanks.

ASTM D 2709 and ASTM D 2276 are not utilized at MNGP. NUREG-1801, Section XI.M30, recommends the use of ASTM Standards D 1796 and D 2709 to test for water and sediment in diesel fuel oils. MNGP uses only ASTM D 1796 for verification that water and sediment are within specified limits. This standard is applicable to the grade of diesel fuel oil used at MNGP. NUREG-1801, Section XI.M30, also recommends the use of a modified ASTM D 2276 for sampling of particulate contaminants. MNGP uses ASTM Standard D 6217 as a laboratory test to sample diesel fuel oil for suspended particulates. This standard is applicable to the grade of diesel fuel oil used at MNGP. This standard utilizes the more conservative filter pore size of 0.8 µm versus the recommended 3.0 µm.

MNGP procedures for testing for sediment in the diesel fuel oil are not based on ASTM D 2709. MNGP uses the requirements of ASTM D 1796 and Table 1 of ASTM D 975 to provide limits on water, sediment and viscosity in diesel fuel oil used at MNGP. ASTM D 1796 is the applicable standard for the grade of diesel fuel oil used at MNGP. Per the MNGP procedure for diesel fuel oil quality checks, MNGP bases particulate contamination (sediment) testing on ASTM D 6217, Standard Test Method for Particulate Contamination in Middle Distillate Fuels by Laboratory Filtration. Although the NUREG-1801 guidance discusses the use of a modified ASTM D 2276, Standard Test Method for Particulate Contaminant in Aviation Fuel by Line Sampling, this standard is not used as the basis for MNGP's particulate sampling. ASTM D 6217-98 requirements for sample size and filter pore size have proven to be more conservative for MNGP than ASTM D 2276. This method of monitoring and controlling fuel oil contamination has resulted in MNGP not having a need to use biocides. This is an acceptable means for monitoring and controlling fuel oil contamination at MNGP and is the equivalent of utilizing ASTM D 2709 and ASTM D 2276 as supported by plant operating experience.

Samples are taken in accordance with ASTM D 4057 and are shipped to an approved laboratory for analysis, in accordance with the MNGP Quality Assurance (QA) program. Qualified technicians using approved test equipment process the samples and reports are generated and sent back to the plant for review and retention. MNGP procedures include the following ASTM standards:
ASTM D 975 for purchasing of Diesel Fuel Oil
ASTM D 4057 for sampling
ASTM D 6217 for testing for particulates
ASTM D 1796 for testing for water and sediment
ASTM D 287 for testing API gravity

The Emergency Diesel Generator day tanks and base tanks are visually checked monthly for water and sediment. The Diesel Oil Storage Tank (T-44) is sampled monthly for particulate contamination and quarterly to verify the diesel fuel oil is within the acceptable limits for viscosity, water and sediment. The Diesel Oil Storage Tank is drained and inspected if deemed necessary based on the trends indicated by the results of the diesel fuel oil analysis, or as recommended by the System Engineer based on equipment operating experience. Internal tank inspections will identify loss of material due to various aging mechanisms, including general, crevice, galvanic, and pitting corrosion and Microbiologically
Influenced Corrosion (MIC).

The MNGP Fuel Oil Chemistry Program provides reasonable assurance that the aging effect of loss of material caused by various corrosion mechanisms and cracking, including biological contaminants, will be adequately managed. The diesel fuel oil system components that are covered by this program will continue to perform their intended

functions for the period of extended operation. The diesel fuel oil monthly and quarterly sampling and trending have confirmed the adequacy of the diesel fuel oil supply. Past tank cleanings and inspections have verified that the condition of the tanks has not degraded.

A review of MNGP condition reports for the diesel fuel oil subsystem tanks that are in the License Renewal scope (Diesel Oil Storage Tank (T-44), the two Emergency Diesel Generator Day Tanks (T-45A and T-45B), the Emergency Diesel Generator Base Tanks), and Diesel Fire Pump Day Tank (t-100) do not show any aging management related issues. A review of plant documentation shows that the subject tanks were cleaned and inspected at various times since initial plant startup.

- The Diesel Oil Storage Tank and the two Emergency Diesel Generator Day Tanks were cleaned in August of 1984, which was the first cleaning since startup. A visual inspection of the tank internals showed that they were in excellent condition, with no leaks, cracks, or significant deterioration observed.

- The Diesel Oil Storage Tank and the two Emergency Diesel Generator Day Tanks were cleaned and inspected during the 1993 refuel outage. In addition, the Emergency Diesel Generator Base Tanks were flushed (no internal inspection was performed because these tanks only have a three inch access opening). The work orders and associated inspection memos were reviewed and showed: The internal surfaces of T-44 were in very good condition, other than some minor internal surface pitting found on the bottom of T-44. No significant corrosion, rust or degradation was found. The internal visual inspection of T-45A and T-45B showed that the internal surfaces were all in excellent condition. No significant corrosion, rust, or pitting was found. All welds and piping connections looked good. Complete NDE wall thickness measurements of the top, sides and bottom were made.

- The only tank cleaned and inspected during the 2003 outage was the Diesel Oil Storage Tank (T-44). The controlling work order stated that the tank was cleaned and NDE inspections for wall thickness and condition were performed and that no problems were found. The MNGP Level III review of the inspection results stated that no repairs were indicated or required. A review of condition reports for the subject tanks and discussion with the former diesel fuel oil system engineer has shown acceptable operation of the system in recent years. This operating experience hasn't identified any problems involving water in the diesel fuel oil, particulate contamination, or biological fouling.

Consequently, MNGP does sample fuel oil for biological contaminants as stated above and operating experience has confirmed the absence of biological contaminants and the potential for resultant loss of material due to MIC.

Audit Question No.: B2.1.20-08

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Messitt **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question: 8. GALL suggests that "Thickness measurement of tank bottom surfaces is an acceptable verification program." to ensure that the effectiveness of the program is verified and to ensure that significant degradation is not occurring and the component intended function will be maintained. The LRA does not mention such a measurement. What is MNGP's alternative?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Although the LRA only states "wall thickness measurements", PBD/AMP-017, Fuel Oil Chemistry Program (Section 3.10, B), states that a review of MNGP condition reports for the diesel fuel oil system tanks that are in License Renewal scope (Diesel Oil Storage Tank - T-44, the two Emergency Diesel Generator Day Tanks - T-45A and T-45B, the Emergency Diesel Generator Base Tanks and the Diesel Fire Pump Day Tank - T-100) do not show any age-related issues. A review of plant documentation shows that the tanks were cleaned and inspected at various times since initial plant startup.

The Diesel Oil Storage Tank and the two Emergency Diesel Generator Day Tanks were cleaned in August of 1984, which was the first cleaning since startup. A visual inspection of the tank internals showed that they were in excellent condition, with no leaks, cracks, or significant deterioration observed.

The Diesel Oil Storage Tank and the two Emergency Diesel Generator Day Tanks were cleaned and inspected during the 1993 refueling outage. In addition, the Emergency Diesel Generator Base Tanks were flushed (no internal inspection was performed because these tanks only have a three inch access opening). Work Request Authorizations WRA #'s 92-06184, 92-06189, 92-06192 and associated inspection memos were reviewed and stated: The internal surfaces of T-44 were in very good condition, other than some minor internal surface pitting found on the bottom of T-44. No significant corrosion, rust or degradation was found.

The internal visual inspection of T-45A and T-45B showed that the internal surfaces were all in excellent condition. No significant corrosion, rust, or pitting was found. All welds and piping connections were acceptable. Complete NDE wall thickness measurements of the top, sides and bottom were made.

When the diesel fuel oil system tanks are drained for cleaning, they are also visually inspected for potential degradation. Diesel Oil Storage Tank (T-44) was cleaned and inspected during the 2003 refueling outage. Ultrasonic (UT) thickness measurements of the tank walls and bottom were made (W.O.# 0202752). The MNGP Level III review of the inspection results stated that no repairs were required.

Final Response: Although the LRA only states "wall thickness measurements", the MNGP program basis document for the Fuel Oil Chemistry Program states that a review of MNGP condition reports for the diesel fuel oil system tanks that are in License Renewal scope (Diesel Oil Storage Tank - T-44, the two Emergency Diesel Generator Day Tanks - T-45A and T-45B, the Emergency Diesel Generator Base Tanks and the Diesel Fire Pump Day Tank - T-100) do not show any age-related issues. A review of plant documentation shows that the tanks were cleaned and inspected at various times since initial plant startup.

The Diesel Oil Storage Tank and the two Emergency Diesel Generator Day Tanks were cleaned in August of 1984, which was the first cleaning since startup. A visual inspection of the tank internals showed that they were in excellent condition, with no leaks, cracks, or significant deterioration observed.

The Diesel Oil Storage Tank and the two Emergency Diesel Generator Day Tanks were cleaned and inspected during the 1993 refueling outage. In addition, the Emergency Diesel Generator Base Tanks were flushed (no internal inspection was performed because these tanks only have a three inch access opening). Plant work orders and associated inspection memos were reviewed and stated:
The internal surfaces of T-44 were in very good condition, other than some minor internal surface pitting found on the bottom of T-44. No significant corrosion, rust or degradation was found.

The internal visual inspection of T-45A and T-45B showed that the internal surfaces were all in excellent condition. No significant corrosion, rust, or pitting was found. All welds and piping connections were acceptable. Complete NDE wall thickness measurements of the top, sides and bottom were made.

When the diesel fuel oil system tanks are drained for cleaning, they are also visually inspected for potential degradation. Diesel Oil Storage Tank (T-44) was cleaned and inspected during the 2003 refueling outage. A review of the plant work orders confirmed that Ultrasonic (UT) thickness measurements of the tank walls and bottom were made. The MNGP Level III review of the inspection results stated that no repairs were required.

Audit Question No.: B2.1.20-09

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Messitt **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question: 9. You have stated that your enhancements will bring the program into consistency with the GALL, what documents the commitments and tracks their completion?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The LRA cover letter includes all of the commitments made in the LRA. All commitments and tracking of same are addressed by the MNGP Corrective Action Program. JPP 6/10/05

Final Response: The LRA cover letter includes all of the commitments made in the LRA. All commitments and tracking of same are addressed by the MNGP Corrective Action Program.

Audit Question No.: B2.1.22-10

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Messitt **MNGP Owner:** Ray Dennis **Discipline:** Civil

Question: 10. GALL suggests that "The number and magnitude of lifts made by the crane are also reviewed." MNGP has taken exception to this for all but the TB Crane. Your LRA states, "...because administrative controls are implemented to ensure that only allowable loads are handled and fatigue failure of structural elements is not expected due to a limited number of lifts." This appears to describe a "review" of lifts. Please clarify how this is an exception.

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: When the GALL states that "the number and magnitude of lifts...are also reviewed", it was thought that a review of an actual log delineating each lift and its magnitude would be performed. Since no logs exist except for special lifts by the Turbine Building Crane, it was conservatively considered an exception. From Drawing NX-9005-36-1, the reactor building crane has a capacity of 70,000 lifts at rated capacity of 85 tons. The expected crane usage is conservatively taken as 28 lifts per year of greater than 25.5 tons but less than 85 tons. This results in less than 2000 lifts over a 60 year period which exhibits significant margin using the rated capacity per lift. Considering decreased load cycles would have the effect of further increasing this margin.

Final Response: When the GALL states that "the number and magnitude of lifts...are also reviewed", it was thought that a review of an actual log delineating each lift and its magnitude would be performed. Since no logs exist except for special lifts by the Turbine Building Crane, it was conservatively considered an exception. Review of an MNGP plant drawing for the reactor building crane confirmed that the crane has a capacity of 70,000 lifts at rated capacity of 85 tons. The expected crane usage is conservatively taken as 28 lifts per year of greater than 25.5 tons but less than 85 tons. This results in less than 2000 lifts over a 60 year period which exhibits significant margin using the rated capacity per lift. Considering decreased load cycles would have the effect of further increasing this margin.

Audit Question No.: B2.1.23-01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Messitt **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: What is the proposed methodology for determination of sample size for the program? What are the criteria for expansion of the sample size?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Sample size will be determined for each Sample Group by selecting a sufficient number of readily accessible "most susceptible to aging effects" locations to ensure representative coverage of the Sample Group. Sample numbers and locations will be determined by an Expert Panel consisting of License Renewal and plant personnel knowledgeable in equipment and effects and material condition. A selection strategy will be used by the panel based on technical literature, industry experience, and recent plant inspection results. In those areas where sufficient plant experience is not available to assess internal equipment conditions, visual and/or NDE techniques will be used to perform inspections. As discussed in response to B2.1.23-02, the entire population of components included in the One Time Inspection Program have been binned into six separate Sample Groups according to program objectives. Selection strategies will be established for each Sample Group.

As stated in the draft sampling method, the criteria for expansion of sample size is:

"If the inspections detect degradation, the results will be evaluated by engineering. If acceptance criteria are not met, an Action Request will be prepared and evaluated through the Corrective Action Program. The evaluation will consider impacts on component intended function(s) over the period of extended operation. Unacceptable results will be evaluated further for extent of condition, need for additional inspections, etc."

Final Response: Sample size will be determined for each Sample Group by selecting a sufficient number of readily accessible "most susceptible to aging effects" locations to ensure representative coverage of the Sample Group. Sample numbers and locations will be determined by an Expert Panel consisting of License Renewal and plant personnel knowledgeable in equipment and effects and material condition. A selection strategy will be used by the panel based on technical literature, industry experience, and recent plant inspection results. In those areas where sufficient plant experience is not available to assess internal equipment conditions, visual and/or NDE techniques will be used to perform inspections. As discussed in response to B2.1.23-02, the entire population of components included in the One Time Inspection Program have been binned into six separate Sample Groups according to program objectives. Selection strategies will be established for each Sample Group.

As stated in the draft sampling method, the criteria for expansion of sample size is:

"If the inspections detect degradation, the results will be evaluated by engineering. If acceptance criteria are not met, an Action Request will be prepared and evaluated through the Corrective Action Program. The evaluation will consider impacts on component intended function(s) over the period of extended operation. Unacceptable results will be evaluated further for extent of condition, need for additional inspections, etc."

Audit Question No.: B2.1.23-02

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Messitt **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: How will the various categories of equipment be binned?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Equipment will be binned by One Time Program objective to ensure the reasons for the program have been addressed. Six separate bins (Sample Groups) have been proposed as follows:

- Sample Group 1: Components Subject to a Fuel Oil Environment
This Sample Group includes components subject to a diesel fuel oil environment managed by the Fuel Oil Chemistry Program. It was established to verify the effectiveness of the Fuel Oil Chemistry Program.

- Sample Group 2: Small Bore Class I Piping Subject to Reactor Coolant
This Sample Group includes Class I stainless steel small bore piping, susceptible to cracking, and exposed to reactor coolant. It was established to confirm cracking in small bore piping is not occurring.

- Sample Group 3: Other Components Susceptible to Stress Corrosion Cracking
This Sample Group was established to verify the effectiveness of the Plant Chemistry Program to mitigate cracking. It includes components susceptible to cracking that are exposed to water sources monitored by the Plant Chemistry Program.

- Sample Group 4: Stand Alone One-Time Inspections
This Sample Group includes components not exposed to an environment managed by the Plant Chemistry or Fuel Oil Chemistry Programs. These components are not managed by other aging management programs because significant degradation is not expected to occur. One time inspections will be performed to confirm this. This Sample Group includes HVAC components, components exposed to outside air, drain piping, and components typically exposed to air with occasional wetting from water sources controlled by the Plant Chemistry Program.

- Sample Group 5: Components Managed by Plant Chemistry
This Sample Group contains the largest number of components and was established to verify the effectiveness of the Plant Chemistry Program. It includes components susceptible to corrosion that are exposed to water sources monitored by the Plant Chemistry Program.

- Sample Group 6: Boral One Time Inspection
This Sample Group was established to remove and inspect the last boral coupon sample from the fuel pool prior to extended operation.

Final Response: Equipment will be binned by One Time Program objective to ensure the reasons for the program have been addressed. Six separate bins (Sample Groups) have been proposed as follows:

- Sample Group 1: Components Subject to a Fuel Oil Environment
This Sample Group includes components subject to a diesel fuel oil environment managed by the Fuel Oil Chemistry Program. It was established to verify the effectiveness of the Fuel Oil Chemistry Program.

- Sample Group 2: Small Bore Class I Piping Subject to Reactor Coolant
This Sample Group includes Class I stainless steel small bore piping, susceptible to cracking, and exposed to reactor coolant. It was established to confirm cracking in small bore piping is not occurring.

- Sample Group 3: Other Components Susceptible to Stress Corrosion Cracking
This Sample Group was established to verify the effectiveness of the Plant Chemistry Program to mitigate cracking. It includes components susceptible to cracking that are exposed to water sources monitored by the Plant Chemistry Program.

- Sample Group 4: Stand Alone One-Time Inspections
This Sample Group includes components not exposed to an environment managed by the Plant Chemistry or Fuel Oil Chemistry Programs. These components are not managed by other aging management programs because significant degradation is not expected to occur. One time inspections will be performed to confirm this. This Sample Group includes HVAC components, components exposed to outside air, drain piping, and components typically exposed to air with occasional wetting from water sources controlled by the Plant Chemistry Program.

- Sample Group 5: Components Managed by Plant Chemistry
This Sample Group contains the largest number of components and was established to verify the effectiveness of the Plant Chemistry Program. It includes components susceptible to corrosion that are exposed to water sources monitored by the Plant Chemistry Program.

- Sample Group 6: Boral One Time Inspection
This Sample Group was established to remove and inspect the last boral coupon sample from the fuel pool prior to extended operation.

Audit Question No.: B2.1.23-03

Source: **AMP Audit** **Status:** **Sufficient per NRC** **Author:** **Messitt** **MNGP Owner:** **Dave Sexton** **Discipline:** **Programs**

Question: Will the sampling protocol be based on a classical statistical analysis? An Industry Standard? If yes, which one(s)? Please provide copy(ies).

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The sample protocol will not be based on classical statistical analysis. MNGP will adopt a "smart sampling" approach focused on using technical literature, industry experience, and recent plant inspection results to locate and inspect those areas deemed most susceptible to aging that can be reasonably accessed and inspected. Sample locations will be selected on the basis that identifying and selecting the worse case locations is bounding of less severe areas. Some less severe areas will also be selected to confirm this premise.

Final Response: The sample protocol will not be based on classical statistical analysis. MNGP will adopt a "smart sampling" approach focused on using technical literature, industry experience, and recent plant inspection results to locate and inspect those areas deemed most susceptible to aging that can be reasonably accessed and inspected. Sample locations will be selected on the basis that identifying and selecting the worse case locations is bounding of less severe areas. Some less severe areas will also be selected to confirm this premise.

Audit Question No.: B2.1.23-04

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Messitt **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: By what method will the Program verify "the absence of a reduction of neutron absorption capacity of boral"?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The following methods are used to evaluate boral coupons removed from the spent fuel pool:
- Physical observation,
- Neutron attenuation test,
- Weight, specific-gravity, and dimensional checks, and
- Chemical analysis for boron content.

Six coupon sets (3 samples in each set) have been removed from the fuel pool from 1979 through 2000. The seventh, and final set, will be removed and evaluated prior to the period of extended operation. The latest test report for Sample Set 6, which used the above test methods, concluded: "tests revealed that its nuclear properties had not been degraded."

Final Response: The following methods are used to evaluate boral coupons removed from the spent fuel pool:
- Physical observation,
- Neutron attenuation test,
- Weight, specific-gravity, and dimensional checks, and
- Chemical analysis for boron content.

Six coupon sets (3 samples in each set) have been removed from the fuel pool from 1979 through 2000. The seventh, and final set, will be removed and evaluated prior to the period of extended operation. The latest test report for Sample Set 6, which used the above test methods, concluded: "tests revealed that its nuclear properties had not been degraded."

Audit Question No.: B2.1.23-05

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Messitt **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: GALL suggests the for small bore piping: "a plant-specific destructive examination of replaced piping due to plant modifications or NDE that permits inspection of the inside surfaces of the piping is to be conducted to ensure that cracking has not occurred." Your LRA does not discuss the destructive examination, is it your intention to perform such examinations?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Section 3.1.2.2.4.1 of the MNGP LRA discusses the option of destructive testing for piping removed for replacement. (JPP)

Small bore Class I stainless steel piping subject to reactor coolant is susceptible to cracking has been included in the One Time Inspection Program. Examinations will include visual exams during plant startup for signs of leakage and internal examinations of piping if it is removed from service during plant modifications prior to extended operation. Piping in this sample group, in accordance with the plant piping design specification, is connected by socket welds. Appropriate internal examination techniques will be used on piping removed from service. This includes the use of destructive examination if determined to be the most effective inspection method.

Final Response: Section 3.1.2.2.4.1 of the MNGP LRA discusses the option of destructive testing for piping removed for replacement.

Small bore Class I stainless steel piping subject to reactor coolant is susceptible to cracking has been included in the One Time Inspection Program. Examinations will include visual exams during plant startup for signs of leakage and internal examinations of piping if it is removed from service during plant modifications prior to extended operation. Piping in this sample group, in accordance with the plant piping design specification, is connected by socket welds. Appropriate internal examination techniques will be used on piping removed from service. This includes the use of destructive examination if determined to be the most effective inspection method.

Audit Question No.: B2.1.23-06

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Messitt **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: What documents the answers to these questions? (Note: questions are B2.1.23-01 through 05)

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The document which answers Questions B2.1.23-01 through 05 is the "Monticello Nuclear Generating Plant One Time Inspection Program Sampling Method", Revision Draft A. This document is still under development. Some operating experience and plant reviews are still required in order to issue a final document. Upon approval, it will become a plant implementing procedure. A separate procedure will also be developed and issued that contains required examination techniques and acceptance criteria. These two procedures will then serve as the basis for developing inspection procedures and work orders to perform the required examinations and to evaluate inspection results.

Final Response: The document which answers Questions B2.1.23-01 through 05 is the "Monticello Nuclear Generating Plant One Time Inspection Program Sampling Method", Revision Draft A. This document is still under development. Some operating experience and plant reviews are still required in order to issue a final document. Upon approval, it will become a plant implementing procedure. A separate procedure will also be developed and issued that contains required examination techniques and acceptance criteria. These two procedures will then serve as the basis for developing inspection procedures and work orders to perform the required examinations and to evaluate inspection results.

Audit Question No.: B2.1.23-07

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Messitt **MNGP Owner:** Dave Sexton **Discipline:** Programs

Question: A project document for the One-Time Inspection Program indicates NRC Information Notice 97-46, "Unisolable Crack in High Pressure Injection Piping", is not applicable because it applies to PWRs. Clarification is required. Thermal stresses described in the Information Notice as a possible cause of crack initiation and propagation are not unique to PWRs.

Date Received: 6/14/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Plant assessment of Information Notice 97-46 indicated the main issue described in the notice was specific to a PWR design (i.e., excessive thermal stresses due to cold water at high pressure leaking into hot reactor coolant system piping). The assessment further noted this issue had been previously evaluated in response to NRC IE Bulletin 88-08 and Information Notice 97-19. Monticello's response to NRC Bulletin 88-08 was transmitted to the NRC on September 2, 1988 and noted no action was required. Monticello identified the shutdown cooling, core spray, condensate, reactor water cleanup, vessel water make-up portion of the CRD System and the CRD pump sealing supply to the reactor recirculation pumps to be at higher pressure than the (hot) reactor coolant system only during early parts of plant startup and the latter part of plant shutdown. Also, the Standby Liquid Control System was identified to be at a higher pressure during its monthly test and the CRD piston drive water is at higher pressure during normal operation. It was determined that for all these identified reactor coolant system unisolable piping locations, the temperature differences were not large enough to cause excessive thermal stresses in the unisolable piping per applicable codes. Supplements 1 to 3 to Bulletin 88-08 were also evaluated and no further action was required as noted by letter to the NRC dated May 21, 1990. PBB 6/14/05

Final Response: Plant assessment of Information Notice 97-46 indicated the main issue described in the notice was specific to a PWR design (i.e., excessive thermal stresses due to cold water at high pressure leaking into hot reactor coolant system piping). The assessment further noted this issue had been previously evaluated in response to NRC IE Bulletin 88-08 and Information Notice 97-19. Monticello's response to NRC Bulletin 88-08 was transmitted to the NRC on September 2, 1988 and noted no action was required. Monticello identified the shutdown cooling, core spray, condensate, reactor water cleanup, vessel water make-up portion of the CRD System and the CRD pump sealing supply to the reactor recirculation pumps to be at higher pressure than the (hot) reactor coolant system only during early parts of plant startup and the latter part of plant shutdown. Also, the Standby Liquid Control System was identified to be at a higher pressure during its monthly test and the CRD piston drive water is at higher pressure during normal operation. It was determined that for all these identified reactor coolant system unisolable piping locations, the temperature differences were not large enough to cause excessive thermal stresses in the unisolable piping per applicable codes. Supplements 1 to 3 to Bulletin 88-08 were also evaluated and no further action was required as noted by letter to the NRC dated May 21, 1990.

Audit Question No.: B2.1.27-01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Messitt **MNGP Owner:** Ray Dennis **Discipline:** Civil

Question: 1. GALL suggests that position C4 of RG1.54, Rev 1, which references ASTM D 5163-96, provides guidelines that are acceptable to the staff for establishing an in-service coatings monitoring program. Why doesn't MNGP reference this Reg Guide and ASTM or identify this as a specific exception to the GALL?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The GALL also states that a program in accordance with RG 1.54, Rev.0 or the ANSI standards referenced in RG 1.54, Rev. 0 is also an acceptable aging management program. As outlined in MNGP's response to GL 98-04, service level 1 coatings are subject to the requirements of ANSI N101.4-1972, to the extent specified in ANSI N18.7-1976 and as modified by RG 1.54, June 1973. MNGP has not committed to RG 1.54, Rev.1. Instead, MNGP has committed to RG 1.54, Rev. 0, ANSI N101.4 and ANSI N101.2. The GALL indicates that this is an acceptable aging management program.

Final Response: The GALL also states that a program in accordance with RG 1.54, Rev.0 or the ANSI standards referenced in RG 1.54, Rev. 0 is also an acceptable aging management program. As outlined in MNGP's response to GL 98-04, service level 1 coatings are subject to the requirements of ANSI N101.4-1972, to the extent specified in ANSI N18.7-1976 and as modified by RG 1.54, June 1973. MNGP has not committed to RG 1.54, Rev.1. Instead, MNGP has committed to RG 1.54, Rev. 0, ANSI N101.4 and ANSI N101.2. The GALL indicates that this is an acceptable aging management program.

Audit Question No.: B2.1.27-02

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Messitt **MNGP Owner:** Ray Dennis **Discipline:** Civil

Question: What is the justification for a 5 year frequency of below torus water level inspections instead of the GALL recommended frequency?

Date Received: 6/13/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The below water line painted surfaces inspections are required to be performed at intervals not exceeding five years. NUREG-1801 specifies that the inspection frequency to be each refueling outage or major maintenance outage. The NUREG also cites ASTM D 5163-96 as the source of the frequency requirement. However, ASTM D 5163-96 specifies that the owner/operator determine the inspection frequency and that it is recommended that the inspections be performed every refueling or major maintenance outage. The protective coatings program is only credited for preventing coating failure that could adversely affect the operation of the ECCS suction strainers. The inability to complete paint repairs, unless the torus is drained, has been factored into evaluations of debris loading on the ECCS suction strainers. The paint debris loading on the ECCS suction strainers allows for up to 1000 square feet of paint chips. After the 2003 inspection, it was estimated that the total area of flaking paint was less than 2 square feet. MNGP operating history has shown only minor coatings issues. There is a large allowance for paint chip debris loading on the ECCS suction strainers. Therefore, a five year frequency for underwater inspections is deemed sufficient.

Final Response: The below water line painted surfaces inspections are required to be performed at intervals not exceeding five years. NUREG-1801 specifies that the inspection frequency to be each refueling outage or major maintenance outage. The NUREG also cites ASTM D 5163-96 as the source of the frequency requirement. However, ASTM D 5163-96 specifies that the owner/operator determine the inspection frequency and that it is recommended that the inspections be performed every refueling or major maintenance outage. The protective coatings program is only credited for preventing coating failure that could adversely affect the operation of the ECCS suction strainers. The inability to complete paint repairs, unless the torus is drained, has been factored into evaluations of debris loading on the ECCS suction strainers. The paint debris loading on the ECCS suction strainers allows for up to 1000 square feet of paint chips. After the 2003 inspection, it was estimated that the total area of flaking paint was less than 2 square feet. MNGP operating history has shown only minor coatings issues. There is a large allowance for paint chip debris loading on the ECCS suction strainers. Therefore, a five year frequency for underwater inspections is deemed sufficient.

Audit Question No.: B2.1.27-03

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Messitt **MNGP Owner:** Ray Dennis **Discipline:** Civil

Question: When will the next torus draining occur?

Date Received: 6/13/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: It is planned to drain the torus and make coatings repairs during the next refueling outage in 2007. The required coatings repairs are in the MNGP corrective action process and are budgeted for the 2007 refueling outage.

Final Response: It is planned to drain the torus and make coatings repairs during the next refueling outage in 2007. The required coatings repairs are in the MNGP corrective action process and are budgeted for the 2007 refueling outage.

Audit Question No.: B2.1.27-04

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Messitt **MNGP Owner:** Ray Dennis **Discipline:** Civil

Question: Are the coatings inspectors qualified to ASTM Guide D4537 or ANSI N45.2.6?

Date Received: 6/15/2005 Potential Submittal on ☑ Potential LRA Update Required ☑ Assoc LRA Section - Appendix B

Draft Response: The inspectors who perform the periodic inspections are qualified to plant procedures and acceptance criteria. However, they are not necessarily qualified to ASTM Guide D4537 or ANSI N45.2.6. Prior to the period of extended operation, all coating inspectors will meet the requirements of ANSI N45.2.6.

Final Response: The inspectors who perform the periodic inspections are qualified to plant procedures and acceptance criteria. However, they are not necessarily qualified to ASTM Guide D4537 or ANSI N45.2.6. Prior to the period of extended operation, all coating inspectors will meet the requirements of ANSI N45.2.6.

Audit Question No.: B2.1.27-11

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Messitt **MNGP Owner:** Ray Dennis **Discipline:** Civil

Question: 11. GALL notes that GL 98-04 describes industry experience pertaining to coatings degradation inside containment and the consequential clogging of sump strainers. Your LRA does not reference the use of GL 98-04 for Operating Experience information. Give some examples of the ways that MNGP identifies coatings specific OE for inclusion in the program?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: In MNGP's response to GL98-04, three inspection procedures are referenced; 0135 (Pressure-Suppression Chamber Painted Surface Internal Inspection), 0140 (Drywell Interior Surface Inspection) and 1367 (Pressure-Suppression Chamber Below Water Line Painted Surface Internal Inspection). These procedures were reviewed for coatings OE. These inspections identified the following signs of paint degradation: chipping, rusting, peeling, blistering, cracking and other signs of degradation. All unacceptable coating degradation has been repaired or in the case of the torus is scheduled for repair during the next torus draining.

Final Response: In MNGP's response to GL98-04, three inspection procedures are referenced. This procedures concern pressure-suppression chamber painted surface internal inspection, drywell interior surface inspection and pressure-suppression chamber below water line painted surface internal inspection. These procedures were reviewed for coatings OE. These inspections identified the following signs of paint degradation: chipping, rusting, peeling, blistering, cracking and other signs of degradation. All unacceptable coating degradation has been repaired or in the case of the torus is scheduled for repair during the next torus draining.

Audit Question No.: B2.1.26-01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Traiforos **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question:

A number of relief requests were cited throughout the LRA. Examples include many relief requests in B2.1.26, "Primary Containment In-Service Inspection Program." The verbiage in the LRA implied that these relief requests were not exceptions to NUREG 1801 since they were approved by the NRC and they were applicable during the period of extended operation.

10 CRF 50.54 states that the license renewal application must contain information for each structure and component within the scope of license renewal concerning the demonstration that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operations.

Please identify the code cases and relief associated with aging management of structures and components within the scope of license renewal. Explain how the structures and components aging effects associated with the code cases and relief requests will be managed. Provide background documentation and indicate planned changes to the LRA.

Date Received: 6/14/2005 Potential Submittal on ☑ Potential LRA Update Required ☑ Assoc LRA Section - Appendix B

Draft Response:

Select relief requests were described in the LRA as they are part of the current Monticello ASME Section XI programs that are credited for managing aging effects. Code cases and relief requests were not considered exceptions to NUREG 1801 as they are temporary in nature and, in many cases, expire prior to the period of extended operation. The code cases and relief requests of the Monticello ASME Section XI, Subsections IWE Inservice Inspection Program are valid through the first inspection interval, which ends prior to the period of extended operation on September 8, 2008. The code cases and relief requests of the Monticello ASME Section XI In-Service Inspection, Subsections IWB, IWC, IWD and IWF are valid for approximately 21 months into the period of extended operation. The program for the current inspection interval ends May 31, 2012.

In addition to the temporary nature of code cases and relief requests (i.e., alternatives), alternatives that carry into the period of extended operation were reviewed and determined to not impact aging management and were, therefore, not considered exceptions to NUREG-1801. The results of this evaluation are included in the attached table.

Based on recent discussions with the NRC, it has become apparent that some of these alternatives should be considered exceptions to NUREG-1801. Though statements in the LRA are correct based on the above discussion, the following clarification is provided:

The alternatives presently implemented by the ASME Section XI In-Service Inspection, Subsections IWB, IWC, IWD and IWF Programs have no impact on aging management. However, some alternatives alter the method in which the ASME Section XI In-Service Inspection Program manages aging as compared to the description of the programs as contained in NUREG-1801, Chapter XI. Therefore, these alternatives will be considered exceptions to NUREG-1801 where relied upon in the Monticello aging management programs.

The above clarification should be used in lieu of any statements in the LRA indicating: "Exceptions to ASME Code requirements that have been granted by approved Code Cases or relief requests, or modifications by 10 CFR 50.55a are not considered to be exceptions to NUREG-1801 criteria."

Final Response:

Select relief requests were described in the LRA as they are part of the current Monticello ASME Section XI programs that are credited for managing aging effects. Code cases and relief requests were not considered exceptions to NUREG 1801 as they are temporary in nature and, in many cases, expire prior to the period of extended operation. The code cases and relief requests of the Monticello ASME Section XI, Subsections IWE Inservice Inspection Program are valid through the first inspection interval, which ends prior to the period of extended operation on September 8, 2008. The code cases and relief requests of the Monticello ASME Section XI In-Service Inspection, Subsections IWB, IWC, IWD and IWF are valid for approximately 21 months into the period of extended operation. The program for the current inspection interval ends May 31, 2012.

In addition to the temporary nature of code cases and relief requests (i.e., alternatives), alternatives that carry into the period of extended operation were reviewed and determined to not impact aging management and were, therefore, not considered exceptions to NUREG-1801. The results of this evaluation are included in the attached table.

Based on recent discussions with the NRC, it has become apparent that some of these alternatives should be considered exceptions to NUREG-1801. Though statements in the LRA are correct based on the above discussion, the following clarification is provided:

The alternatives presently implemented by the ASME Section XI In-Service Inspection, Subsections IWB, IWC, IWD and IWF Programs have no impact on aging management. However, some alternatives alter the method in which the ASME Section XI In-Service Inspection Program manages aging as compared to the description of the programs as contained in NUREG-1801, Chapter XI. Therefore, these alternatives will be considered exceptions to NUREG-1801 where relied upon in the Monticello aging management programs.

The above clarification should be used in lieu of any statements in the LRA indicating: "Exceptions to ASME Code requirements that have been granted by approved Code Cases or relief requests, or modifications by 10 CFR 50.55a are not considered to be exceptions to NUREG-1801 criteria."

The following audit question responses are encompassed by this audit question (B2.1.26-01): Audit questions No. B2.1.2-03, B2.1.2-07, B2.1.2-13, B2.1.26-01a, B2.1.26-02, B2.1.26-03, B2.1.26-04, B2.1.26-05, B2.1.28-01, and B2.GEN-01.

This audit question (B2.1.26-01) does not adequately address all the concerns listed in the following audit questions B2.1.2-01, B2.1.10-01, and B2.1.9-03. The entire audit question and response are discussed below:

(1) Audit Question No. B2.1.2-01

Audit Question Text:
1. The Program Description for AMP XI.M1 in NUREG-1801, April 2001, states that "this program generally includes ...all Class 1, 2 and 3 pressure retaining components and their integral attachments." The MNGP LRA Program Description for MNGP AMP B2.1.2 (ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD) states that Class 1 and 2 piping is being inspected in accordance with the RI-ISI as described in EPRI TR-112657. It is not clear from the description in MNGP LRA whether certain categories or types of Class 1 and 2 piping components may have been excluded from the AMP as implemented at MNGP on the basis of RI-ISI. Please provide additional information in this regard:

Has RI-ISI been credited to exclude from inspections any categories or types of piping components that would otherwise be included in the inspections required by ASME Section XI 1995 Edition through the 1996 Addenda? If so, please identify the component categories or types and briefly discuss the justification for their exclusion.

Audit Question Response:
In MNGP's License Renewal ASME Section XI AMP, the RI-ISI is not credited for excluding from inspection any categories or types of piping components that would otherwise be included as required by ASME Section XI 1995 Edition through the 1996 Addenda. Also see response to Audit Question No. B2.1.26-01.

(2) Audit Question No. B2.1.10-01

Audit Question Text:
PBD/AMP-038 says that, "At MNGP, all IGSCC susceptible materials have been replaced or protected with a cladding of resistant weld material. Therefore, all piping welds are now classified as IGSCC Category A in accordance with NUREG-0313 and GL 88-01." In Section 3.10.B the PBD also says, "All piping welds are now classified as IGSCC Category A in accordance with NUREG-0313 and GL 88-01 and are being examined in accordance with the Risk Informed Inservice Inspection Program."

MNGP DBD-T12 (Design Basis Document: Plant Piping), Revision D, Section 2.3.23.B.2) identifies one of the corrective actions proposed in response to GL 88-01 as, "Inspect welds not meeting Category A requirements of NUREG-0313, Rev. 2, at each refueling outage and replace if crack indications are found or replace as a preventative

measure during a future outage."

QUESTION:
Since all IGSCC susceptible material has been replaced or protected with a cladding of resistant weld material, on what frequency are these welds now inspected? What is the technical and/or regulatory basis for that inspection frequency?

Audit Question Response:
The BWR Stress Corrosion Cracking AMP is applicable to all BWR piping made of austenitic stainless steel that is 4 inches or larger in nominal diameter and contains reactor coolant at a temperature above 93°C (200°F) during power operation, regardless of code classification. GL 88-01 requires an augmented ASME Section XI ISI Program to inspect welds that are not classified as Category A. All piping welds at Monticello are now classified as IGSCC Category A in accordance with NUREG-0313 and GL 88-01 and the augmented ASME Section XI ISI inspection frequency of GL 88-01 no longer applies for any welds. Therefore, all piping welds are scheduled and being examined in accordance with the Risk Informed Inservice Inspection Program. Also see response to Audit Question No. B2.1.26-01.

(3) Audit Question No. B2.1.9-03

Audit Question Text:
PBD/AMP-039 says that, "Code inspection are enhanced with inspections consistent with the requirements of BWRVIP-27 and BWRVIP-49 and an NRC approved alternative (RI-ISI)."

QUESTION:
With regard to aging management of BWR Penetrations, please describe the effects on this program introduced by MNGP's implementation of RI-ISI.

Audit Question Response:
RI-ISI reduced the number of welds being inspected for ASME Section XI, ISI, Examination Categories B-F and B-J. The welds were selected based on their susceptibility to aging mechanisms and the consequences of their failure rather than the ASME Section XI ISI required sample population. Also see response to Audit Question No. B2.1.26-01.

See also Tables addressing approved Code alternatives and approved Code Cases in NMC letter to NRC dated August 11, 2005 (Source Documents 2 & 3).

Audit Question No.: B2.1.26-01a

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Traiforos **MNGP Owner:** Madalin O'Brien **Discipline:** Civil

Question:

In the discussion of "NUREG-1801 Consistency" of B2.1.26, Primary Containment In-Service Inspection Program, it is stated that "Exceptions to ASME Code requirements that have been granted by approved Code Cases or relief requests are not considered to be exceptions to NUREG-1801 criteria."

The Staff does not accept this position. The 10 CFR 50.55a relief request process, which is an existing regulatory process not connected with license renewal, approves a relief for a specified time (not to exceed 10 years - which means that any given relief will not be good for the entire period of extended operation). After that time, the licensee is required to re-justify the basis for the relief. The NRC will perform another review at that time and may or may not grant the relief. In any event, however, a relief is not based on compliance with 10 CFR 54.21(a)(3). Therefore the cited relief requests, which are within the scope of license renewal, should be justified as exceptions.
Examples of cited, in B2.1.26, activities approved by relief requests, and therefore should be justified as exceptions, include (exact quotes):

1. The current MNGP program does not require the examination of seals & gaskets, the measurement of residual bolt torque, the pre-service examination of new coatings or the pre-removal examination of existing coatings. These are not considered exceptions since the MNGP program has been reviewed by the NRC and is in accordance with 10CFR50.55a with NRC approved relief requests.

2. The program requires a General Visual examination of all accessible surfaces, except submerged surfaces, once during each period. It requires a VT-3 visual examination of all accessible surfaces, including submerged surfaces, once during each interval. Sub-Section IWE requires the VT-3 examination to be done at the end of the interval. The MNGP program allows a part of this exam to be done during each period. This is not considered an exception since the MNGP program has been reviewed by the NRC and is in accordance with 10CFR50.55a with NRC approved relief requests.

3. The MNGP Program allows the need for augmented examination of repaired areas to be based on engineering evaluation rather than on the prescriptive requirements of Sub-Section IWE. This is not considered an exception since the MNGP program has been reviewed by the NRC and is in accordance with 10CFR50.55a with NRC approved relief requests.

4. Per plant administrative procedures, repairs/replacements and re-examinations comply with IWA-4000. The MNGP Program for the 4th 10 year In-service Inspection Interval allows the 2001 Edition of Section XI to be used for IWA-4000. This is not considered an exception since the MNGP program has been reviewed by the NRC and is in accordance with 10CFR50.55a with NRC approved relief requests.

Date Received: 6/9/2005 Potential Submittal on ☑ Potential LRA Update Required ☑ Assoc LRA Section - Appendix B

Draft Response:

See response to B2.1.26-01.

Relief Requests are part of the current MNGP Program for containment inspections but are not considered part of MNGP's License Renewal Primary Containment ISI Aging Management Program (AMP). Per the Dresden/Quad Cities SER, NUREG 1796, "The staff position is that current Relief Requests granted by the staff have no bearing on License Renewal commitments, because the basis for the relief request and the period of time during which the relief request is applicable generally will not carry over to the period of extended operation. Consequently, for license renewal the staff expects a commitment to IWE and supplemental requirements consistent with 10 CFR 50.55a."

MNGP's position is consistent with the above staff position. The MNGP License Renewal Primary Containment ISI AMP will be in accordance with 10 CFR 50.55a, which includes the process for determining which relief requests and supplemental requirements apply. Relief Requests are subject to periodic review by the NRC under 10CFR 50.55a. It cannot be predicted which existing or new relief requests may be part of the future MNGP License Renewal AMP. Therefore, MNGP will only implement modifications to the program during the extended period of operation as covered in the 1992 Edition with the 1992 Addenda of the ASME Section XI Code, Subsection IWE as modified and supplemented by 10CFR50.55a.

Any language in the LRA referring to "approved relief requests" applies only to the current MNGP Program for containment inspections (IWE) and not to the future MNGP License Renewal Primary Containment ISI AMP. Perhaps the discussion on relief requests should not have been included in the LRA in order to avoid confusion between the

current MNGP Program for containment inspections (IWE) and the MNGP License Renewal Primary Containment ISI Program.

Final Response: See response to B2.1.26-01.

Audit Question No.: B2.1.26-03

Source: **AMP Audit** **Status:** **Sufficient per NRC** **Author:** **Traiforos** **MNGP Owner:** **Madalin O'Brien** **Discipline:** **Civil**

Question: QUESTION 1 - AMP B2.1.26, Primary Containment In-Service Inspection Program (Spyros Traiforos)

The second paragraph under the heading "NUREG-1801 Consistency" states: Exceptions to ASME code requirements that have been granted by Code Cases or relief requests are not considered to be exceptions to NUREG-1801 criteria. Why aren't Code Cases and relief requests considered exceptions?

Date Received: 7/20/2005 Potential Submittal on ☑ Potential LRA Update Required ☑ Assoc LRA Section - Appendix B

Draft Response: See response to question B2.1.26-01.

Final Response: See response to question B2.1.26-01.

Audit Question No.: B2.1.26-04

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Traiforos **MNGP Owner:** Madalin O'Brien **Discipline:** Civil

Question:

QUESTION 2 - AMP B2.1.26, Primary Containment In-Service Inspection Program (Spyros Traiforos)

The project team reviewed the Containment Inspection Examination Plan, Revision 1, "First Interval, September 9, 1998 through September 8, 2008." Seven relief requests are listed for Class MC components (MC-1 through MC-7). Some of these relief requests are discussed in Aging Management Program Basis Document PBD/AMP-022, Revision 1, "Primary Containment In-Service Inspection Program." As part of addressing the issue of relief requests in B2.1.26, please provide a reconciliation of any differences on relief requests among the above three documents as they pertain to the adequacy of B2.1.26 to address the aging management of structures and components involved during the period of extended operation.

Date Received: 7/20/2005 Potential Submittal on ☑ Potential LRA Update Required ☑ Assoc LRA Section - Appendix B

Draft Response:

See response to question B2.1.26-01.
The discussion of relief requests in the aging management program basis document PBD/AMP-022, "Primary Containment In-Service Inspection Program." that exists outside of the boxed text is for information only. Relief requests apply only to the current MNGP Program for containment inspections (IWE) and not to the future MNGP License Renewal Primary Containment ISI AMP.

Final Response:

See response to question B2.1.26-01.

Audit Question No.: B2.1.26-05

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Traiforos **MNGP Owner:** Madalin O'Brien **Discipline:** Civil

Question:

QUESTION 3 - AMP B2.1.26, Primary Containment In-Service Inspection Program (Spyros Traiforos)

According to Element "Detection of Aging Effects," Sub-Section IWE requires the VT-3 examination to be done at the end of the interval. The MNGP program allows a part of this exam to be done during each period. According to the write up in this element, this is not considered an exception since the MNGP program has been reviewed by the NRC and is in accordance with 10CFR55.55a with NRC approved relief requests.

The project team observed that the Inspection Schedule is provided in Tables IWE-2411-1 and IWE-2412-1 of the ASME Section XI Code. Moreover, in Table IWE-2500-1 and in reference to VT-3, it is stated that deferral of inspection to end of interval is permissible. Please clarify the statements in B2.1.26 in light of ASME Section XI Code requirements. Also explain the reference to relief request.

Date Received: 7/20/2005 Potential Submittal on ☑ Potential LRA Update Required ☑ Assoc LRA Section - Appendix B

Draft Response: See response to question B2.1.26-01.

Final Response: See response to question B2.1.26-01.

Audit Question No.: B2.1.30-01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Traiforos **MNGP Owner:** Jim Rootes **Discipline:** Programs

Question:

1. It is stated in B2.1.30, Selective Leaching of Materials, that "The qualitative method used in lieu of the hardness test would typically be an enhanced visual inspection consistent with ASME Section XI, VT-1 requirements. This qualitative method will be augmented, as necessary, by other NDE or metallurgical methods, as appropriate."

The above statements are not very clear. The qualitative methods should be used in lieu of hardness testing and in addition to visual testing. The statements appear to suggest that visual inspection alone may be adequate. Please explain. In addition, identify the NDE or metallurgical methods.

Appendix A2.1.30 and Commitment 42 are more definitive in the use of other NDE or metallurgical methods in addition to visual testing, than the description of the AMP B2.1.30.

Date Received: 6/7/2005 Potential Submittal on ☑ Potential LRA Update Required ☑ Assoc LRA Section - B2.1.30

Draft Response:

The above quote is from Section 3.4, Detection of Aging Effects. Appendix A2.1.30 is the same as the Program Description in Appendix B for the Selective Leaching of Materials AMP. The statement, "In situations where hardness testing is not practical, a qualitative method by other NDE or metallurgical methods will be used" is used several times in the AMP.

The preference, to identify the presence of selection leaching, is the use of visual inspection and hardness testing. However, if the area of interest is not accessible for the use of hardness test equipment, other methods for inspection and evaluation will be used such as enhanced VT-1 in accordance with ASME Section XI criteria and NDE methods that would be capable of identifying the presence of selective leaching. A combination of VT-1 and NDE may be appropriate based on the situation.

Since this is a new aging management program for MNGP, not all methods to detect selective leaching have been researched. The research of field hardness testers has been performed resulting in the identification of potential test equipment. Common NDE methods such as PT, UT, and RT will be evaluated for their capability of determining the presence of selective leaching. It is expected that PT will be used to determine if porosity/surface pitting is present on internal surfaces as applicable. In-situ metallurgical sampling will be performed if possible. In other situations a sample may be removed for analysis to determine the presence of selective leaching and determine the extent of degradation. Industry practices will also be researched for other types of metallurgical methods that may be available to also detect selective leaching.

Response reviewed and concurrence by K Bezzant 8 June 2005
Reviewed by J Pairitz 14 June 2005

Final Response:

The methods to identify the presence of selective leaching are visual inspection in conjunction with mechanistic techniques such as scratch testing, hardness testing, or nondestructive examinations.

Audit Question No.: B2.1.30-02

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Traiforos **MNGP Owner:** Jim Rootes **Discipline:** Programs

Question:

Question:

Commitment 42: Implementation of a new selective leaching aging management program.

Please provide a status of the implementation of the above commitments including scope of work, implementing procedures, inspected and measured parameters, and acceptance criteria. Also, provide the anticipated schedule of completion of the work associated with these commitments.

Date Received: 6/13/2005 Potential Submittal on ☑ Potential LRA Update Required ☑ Assoc LRA Section - B2.1.30

Draft Response:

Response:

The implementation activities for B2.1.30, Selective Leaching of Materials, is still in the development stage. It is expected that implementing instructions/procedures will be drafted later this year. Examples of possible implementing instructions/procedures to be created are:

- An engineering work instruction for managing the overall AMP for selective leaching
- A specific NDE procedure utilizing PT for determining the presence of selective leaching
- A hardness test procedure (based on the test equipment obtained)
- A test location selection procedure using the methodology established for One-Time Inspection (see the One-Time Inspection Program Basis Document)
- A specific visual inspection procedure utilizing enhanced VT-1

Existing site procedures, that are relevant to this AMP, will be evaluated and revised if appropriate.

Research will be conducted of industry practices for applicable methods to test for selective leaching. This research may extend beyond the nuclear industry to industries that have experience with selective leaching. Research has been conducted to identify portable harness test equipment. So far 4 testers have been identified. These will be evaluated for MNGP's specific needs. The tester and relevant test standards will be selected and ordered.

Actual performance of relative aging management of activities is expected to be accomplished in accordance with the existing work control process.

It is expected to have the test equipment and implementing instructions and procedures in place to begin testing for selective leaching during the 2007 refueling outage.

Reviewed by J Pairitz, 14 JUN 05

Final Response:

Response:

The implementation activities for B2.1.30, Selective Leaching of Materials, is still in the development stage. It is expected that implementing instructions/procedures will be drafted later this year. Examples of possible implementing instructions/procedures to be created are:

- An engineering work instruction for managing the overall AMP for selective leaching
- A specific NDE procedure utilizing PT for determining the presence of selective leaching
- A hardness test procedure (based on the test equipment obtained)
- A test location selection procedure using the methodology established for One-Time Inspection (see the One-Time Inspection Program Basis Document)
- A specific visual inspection procedure utilizing enhanced VT-1

Existing site procedures, that are relevant to this AMP, will be evaluated and revised if appropriate.

Research will be conducted of industry practices for applicable methods to test for selective leaching. This research may extend beyond the nuclear industry to industries that have experience with selective leaching. Research has been conducted to identify portable harness test equipment. So far 4 testers have been identified. These will be evaluated for MNGP's specific needs. The tester and relevant test standards will be selected and ordered.

Actual performance of relative aging management of activities is expected to be accomplished in accordance with the existing work control process.

It is expected to have the test equipment and implementing instructions and procedures in place to begin testing for selective leaching during the 2007 refueling outage.

Reviewed by J Pairitz, 14 JUN 05

Audit Question No.: B2.1.31-01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Traiforos **MNGP Owner:** Madalin O'Brien **Discipline:** Civil

Question: 1. The Structures Monitoring Program lists the enhancements which would accommodate the inspections of the Water-Control Structures (Commitments 42, 43, 44, 45, 46, 47 and 48). However, there is no enhancement listed for addressing the aging management of the Masonry Walls. Such an enhancement would require that masonry walls are inspected for cracks in the masonry and degradation of steel edge supports and bracing. Such an inspection would also address the acceptance criteria of XI.S5, Masonry Wall Program.

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Commitment letter L-MT-05-014 dated March 15, 2005 Item #42 refers to LRA Section B2.1.30 (Selective Leaching of Materials as it pertains to metals) and therefore not applicable to B2.1.31.

Masonry walls are in scope of the MNGP License Renewal Structures Monitoring Program without enhancements. They are already inspected as part of the MNGP License Renewal Structures Monitoring Program.

Parameters monitored or inspected for masonry walls will be enhanced to include inspections for cracks in the blocks (Note: The following parameters exist within the program, cracks in the joints, deterioration of penetrations, and missing or broken blocks). Additionally, masonry wall steel support parameters monitored or inspected will be enhanced to include corrosion, deflection, twisted, warped, local deflection, and crack welds (Note: The following parameters exist within the program, angle supports not flush with masonry wall and loose or missing anchors/fasteners). Masonry wall acceptance criteria are including in the MNGP License Renewal Structures Monitoring Program without enhancements. All masonry walls at the MNGP are inspected for degraded conditions, and either the masonry wall is accepted as-is, accepted as-is based on further evaluation, or corrective action is taken to restore the wall to the design basis condition. As part of the MNGP modification process, masonry walls are modified with consideration to plant Modification Special Items to Consider File item # 87-N5. This file contains guidelines for modifications to masonry walls as analyzed and reviewed for IEB 80-11 with acceptance criteria based on codes, established standards of practice, and conservative assumptions used industry wide.

Final Response: Commitment letter L-MT-05-014 dated March 15, 2005 Item #42 refers to LRA Section B2.1.30 (Selective Leaching of Materials as it pertains to metals) and therefore not applicable to B2.1.31.

Masonry walls are in scope of the MNGP License Renewal Structures Monitoring Program without enhancements. They are already inspected as part of the MNGP License Renewal Structures Monitoring Program.

Parameters monitored or inspected for masonry walls will be enhanced to include inspections for cracks in the blocks (Note: The following parameters exist within the program, cracks in the joints, deterioration of penetrations, and missing or broken blocks). Additionally, masonry wall steel support parameters monitored or inspected will be enhanced to include corrosion, deflection, twisted, warped, local deflection, and crack welds (Note: The following parameters exist within the program, angle supports not flush with masonry wall and loose or missing anchors/fasteners). Masonry wall acceptance criteria are including in the MNGP License Renewal Structures Monitoring Program without enhancements. All masonry walls at the MNGP are inspected for degraded conditions, and either the masonry wall is accepted as-is, accepted as-is based on further evaluation, or corrective action is taken to restore the wall to the design basis condition. As part of the MNGP modification process, masonry walls are modified with consideration to plant Modification Special Items to Consider File. This file contains guidelines for modifications to masonry walls as analyzed and reviewed for IEB 80-11 with acceptance criteria based on codes, established standards of practice, and conservative assumptions used industry wide.

Audit Question No.: B2.1.31-02

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Traiforos **MNGP Owner:** Madalin O'Brien **Discipline:** Civil

Question: 2. Commitment 4 states that "The interior of the Diesel Fire Pump House masonry block wall is covered with insulation. The structures monitoring Program will require that the interior surfaces of the walls will be examined if exterior wall surfaces show evidence of significant aging effects." Considering that masonry walls are addressed by the Structures Monitoring Program, doesn't the above examination constitute an enhancement to this AMP?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The MNGP License Renewal Structures Monitoring Program already includes masonry wall inspections. Therefore no enhancements to the Program are required.

Final Response: The MNGP License Renewal Structures Monitoring Program already includes masonry wall inspections. Therefore no enhancements to the Program are required.

Audit Question No.: B2.1.31-03

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Traiforos **MNGP Owner:** Madalin O'Brien **Discipline:** Civil

Question: 3. XI.S5 states that for each masonry wall, the extent of observed cracking of masonry and degradation of steel edge supports and bracing is not to invalidate the evaluation basis. Corrective actions are taken if the extent of cracking and steel degradation is sufficient to invalidate the evaluation basis. An option is to develop a new evaluation basis that accounts for the degraded condition of the wall (i.e., acceptance by further evaluation). This is not explicitly addressed in the Acceptance Criteria of the Structures Monitoring Program.

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Summary level discussion provided in Appendix B of the LRA omitted this discussion on the acceptance criteria for masonry walls, however the MNGP License Renewal Structures Monitoring Program, PBD/AMP-027 includes the following.

NUREG-1801 program XI.S5 requires an engineering evaluation (and subsequent corrective action if found to be necessary) of any observed cracking and/or degradation of steel edge supports & bracing. This engineering evaluation is done to determine if the wall retains the capability to fulfill its intended function (e.g., supporting equipment loads or remaining intact under design basis events).
The MNGP Maintenance Rule structures monitoring requires such an evaluation (and corrective action, if specified in the evaluation report) if cracking or degraded steel edge supports & bracing are found during the examination.
As stated in Response to RAI # - B2.1.31-01, Commitment #45, masonry wall acceptance criteria are including in the MNGP License Renewal Structures Monitoring Program without enhancement. All masonry walls at the MNGP are inspected for degraded conditions, and either the masonry wall is accepted as-is, accepted as-is based on further evaluation, or corrective action is taken to restore the wall to the design basis condition. As part of the MNGP modification process, masonry walls are modified with consideration to plant Modification Special Items to Consider File item # 87-N5. This file contains guidelines for modifications to masonry walls as analyzed and reviewed for IEB 80-11 with acceptance criteria based on codes, established standards of practice, and conservative assumptions used industry wide.

Final Response: Summary level discussion provided in Appendix B of the LRA omitted this discussion on the acceptance criteria for masonry walls, however the MNGP License Renewal Structures Monitoring Program basis document, includes the following.

NUREG-1801 program XI.S5 requires an engineering evaluation (and subsequent corrective action if found to be necessary) of any observed cracking and/or degradation of steel edge supports & bracing. This engineering evaluation is done to determine if the wall retains the capability to fulfill its intended function (e.g., supporting equipment loads or remaining intact under design basis events).
The MNGP Maintenance Rule structures monitoring requires such an evaluation (and corrective action, if specified in the evaluation report) if cracking or degraded steel edge supports & bracing are found during the examination.
As stated in Response to RAI # - B2.1.31-01, Commitment #45, masonry wall acceptance criteria are including in the MNGP License Renewal Structures Monitoring Program without enhancement. All masonry walls at the MNGP are inspected for degraded conditions, and either the masonry wall is accepted as-is, accepted as-is based on further evaluation, or corrective action is taken to restore the wall to the design basis condition. As part of the MNGP modification process, masonry walls are modified with consideration to plant Modification Special Items to Consider File. This file contains guidelines for modifications to masonry walls as analyzed and reviewed for IEB 80-11 with acceptance criteria based on codes, established standards of practice, and conservative assumptions used industry wide.

Audit Question No.: B2.1.31-04

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Traiforos **MNGP Owner:** Madalin O'Brien **Discipline:** Civil

Question: 4. In the discussion of Detection of Aging Effects in the Structures Monitoring Program, reference is made to "critical structures." Please define this term.

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The reference to "critical structures" discussed in Attribute #4, Detection of Aging Effects is referring to the MNGP Intake Structure. NUREG-1801 XI.S7 Inspection of Water-Control Structures Associates with Nuclear Power Plants Program, Attribute # 4, Detection of Aging Effects states, "RG 1.127 also describes special inspections immediately following the occurrence of significant natural phenomena, such as large floods, earthquakes, hurricanes, tornadoes, and intense local rainfalls." Although not a license renewal commitment nor a requirement, inspections following the occurrence of significant natural phenomena are performed for other plant "critical structures" including the Discharge Structure, Turbine Building, Diesel Generator Building, Diesel Fuel Oil Transfer House, EFT Building, Control Building, Reactor Building, Radwaste Building, Off-Gas Stack, and Off-Gas Storage Building, and others.

Final Response: The reference to "critical structures" discussed in Attribute #4, Detection of Aging Effects is referring to the MNGP Intake Structure. NUREG-1801 XI.S7 Inspection of Water-Control Structures Associates with Nuclear Power Plants Program, Attribute # 4, Detection of Aging Effects states, "RG 1.127 also describes special inspections immediately following the occurrence of significant natural phenomena, such as large floods, earthquakes, hurricanes, tornadoes, and intense local rainfalls." Although not a license renewal commitment nor a requirement, inspections following the occurrence of significant natural phenomena are performed for other plant "critical structures" including the Discharge Structure, Turbine Building, Diesel Generator Building, Diesel Fuel Oil Transfer House, EFT Building, Control Building, Reactor Building, Radwaste Building, Off-Gas Stack, and Off-Gas Storage Building, and others.

Audit Question No.: B2.1.31-05

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Traiforos **MNGP Owner:** Madalin O'Brien **Discipline:** Civil

Question:

5. Commitment No. 43, Enclosure 3, of NMC letter L-MT-05-014, dated March 16, 2005, states: "The Structures Monitoring Program will be expanded, as necessary, to include inspections of structures and structural elements in scope for License Renewal that are not inspected as part of another aging management program." Please clarify this statement.

According to B2.1.31, Structures Monitoring Program, the program will be enhanced to implement the NUREG-1801, XI.S6 (Structures Monitoring Program), XI.S5 (Masonry Wall Program) and XI.S7 (Inspection of Water-Control Structures). It is expected that all structural elements within the scope of the above NUREG-1801 programs will be addressed by B2.1.31. Are there other structures and structural elements, outside the scope of the above programs which will also be addressed by B2.1.31? Please explain

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response:

The Structures Monitoring Program manages the aging effects of structures and structural components within the scope of License Renewal that are not covered by another aging management program. For example, aging management of structural components associated with Primary Containment is performed under the ASME Section XI, Subsection IWE Program. Aging management of structural components associated with Hangers and Supports is performed under the ASME Section XI, Subsection IWF and/or the System Condition Monitoring Programs. Aging management of cranes and reactor component handling equipment is performed under the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program. Aging management of the spent fuel pool liner and structural components within the pool is performed under the Plant Chemistry Program. The Structures Monitoring Program includes masonry block walls and water control structures that are in scope for license renewal. The program also provides inspection requirements to manage aging effects as described in Parameters Monitored or Inspected.

Final Response:

The Structures Monitoring Program manages the aging effects of structures and structural components within the scope of License Renewal that are not covered by another aging management program. For example, aging management of structural components associated with Primary Containment is performed under the ASME Section XI, Subsection IWE Program. Aging management of structural components associated with Hangers and Supports is performed under the ASME Section XI, Subsection IWF and/or the System Condition Monitoring Programs. Aging management of cranes and reactor component handling equipment is performed under the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program. Aging management of the spent fuel pool liner and structural components within the pool is performed under the Plant Chemistry Program. The Structures Monitoring Program includes masonry block walls and water control structures that are in scope for license renewal. The program also provides inspection requirements to manage aging effects as described in Parameters Monitored or Inspected.

Audit Question No.: B2.1.31-06

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Traiforos **MNGP Owner:** Ray Dennis **Discipline:** Civil

Question:

6. Enclosure 3 to the letter L-MT-05-014 to the Document Control Desk, dated March 16, 2005, is a compilation of commitments related to license renewal aging management for the Monticello Generating Plant.

Commitments 43, 44, 45, 46, 47 and 48 refer to enhancements of the Structures Monitoring Program, which is an existing program. Commitment 42 refers to the implementation of the Selective Leaching of Materials Program which is a new program. Finally, Commitment 4 refers to examining the interior surfaces of the block walls under the Structures Monitoring Program.

Please provide a status of the implementation of the above commitments, including scope of work, implementing procedures, inspected and measured parameters, and acceptance criteria. Also provide the anticipated schedule of completion of the work associated with the implementation of these commitments.

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response:

The implementation activities for B2.1.31, Structures Monitoring Program, are in the planning and development stage. The expectation is to have all associated implementing instructions/procedures revised and approved prior to the period of extended operation. However, it is the goal to have applicable instructions/procedures revised and approved for activities that can only be performed during refueling outages (scheduled for 2007 and 2009) or other specified conditions, such as water level, time of year, etc.

Existing site instructions/procedures, that are relevant to this AMP, will be revised to include aging management criteria for scope, parameters, and acceptance criteria. One MNGP procedure dealing with periodic structural inspection has already been revised and progressing through MNGP's document control process for review and approval. This procedure was specifically revised to include aging management criteria relevant to the Structures Monitoring Program. Industry guidance, such as EPRI Aging Assessment Field Guide, will be used in identifying appropriate parameters to monitor and acceptance criteria.

License Renewal implementing process procedures are being drafted. It is expected that these procedures will be completed prior to September 2005. The License Renewal implementing process will include an implementation plan that will include tracking actions for implementation and monitoring the status of progress. These procedures will require MNGP implementing instructions/procedures to follow site document control procedures that include submittal and tracking via the document control tracking process. The License Renewal implementing process will also require entering these documents either the License Renewal action tracking database or the site corrective action process to ensure timely processing of implementing instructions/procedures.

It is the goal to have the revised instructions/procedures in place to allow sufficient time for task performers to be trained and qualified, if appropriate, in the related aging management criteria.

Final Response:

The implementation activities for B2.1.31, Structures Monitoring Program, are in the planning and development stage. The expectation is to have all associated implementing instructions/procedures revised and approved prior to the period of extended operation. However, it is the goal to have applicable instructions/procedures revised and approved for activities that can only be performed during refueling outages (scheduled for 2007 and 2009) or other specified conditions, such as water level, time of year, etc.

Existing site instructions/procedures, that are relevant to this AMP, will be revised to include aging management criteria for scope, parameters, and acceptance criteria. One MNGP procedure dealing with periodic structural inspection has already been revised and progressing through MNGP's document control process for review and approval. This procedure was specifically revised to include aging management criteria relevant to the Structures Monitoring Program. Industry guidance, such as EPRI Aging Assessment Field Guide, will be used in identifying appropriate parameters to monitor and acceptance criteria.

License Renewal implementing process procedures are being drafted. It is expected that these procedures will be completed prior to September 2005. The License Renewal implementing process will include an implementation plan that will include tracking actions for implementation and monitoring the status of progress. These procedures will require MNGP implementing instructions/procedures to follow site document control procedures that include submittal and tracking via the document control tracking process. The License Renewal implementing process will also require entering these documents either the License Renewal action tracking database or the site corrective action

process to ensure timely processing of implementing instructions/procedures.

It is the goal to have the revised instructions/procedures in place to allow sufficient time for task performers to be trained and qualified, if appropriate, in the related aging management criteria.

Audit Question No.: B2.1.31-07

Source: **AMP Audit** **Status:** **Sufficient per NRC** **Author:** **Traiforos** **MNGP Owner:** **Madalin O'Brien** **Discipline:** **Civil**

Question: 7. On page 3-767 of the LRA, plant specific-note 515 states: "Concrete is inspected as part of the Structures Monitoring Program. In addition, since the System Condition Monitoring Program performs support inspections, the concrete surrounding the support base plates and anchor bolts is also inspected as part of the System Condition Monitoring Program. Therefore, both the Structures Monitoring Program and the System Condition Monitoring Program identify and evaluate cracking and other concrete aging mechanisms.

The review of AMP B2.1.32, System Condition Monitoring Program, in the LRA, revealed no explicit reference to concrete. However, there is one reference to inspections and walk downs to monitor for evidence of material degradation for mechanical systems/components and civil structures. Do "civil structures" include concrete structures? Please provide the inspection procedure(s) of the System Condition Monitoring Program that perform the inspection of concrete.

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The reference in the System Condition Monitoring Program to, "civil structures" includes concrete local to component supports.

The MNGP System Walkdown Guideline (found on the MNGP Engineering Web Page) and Conduct of System Engineering, EWI-01.04.06 are implementing procedures for the System Condition Monitoring Program. Theses procedures will be enhanced to include parameters inspected for concrete at locations of expansion and grouted anchors and grout pads for support base plates. EPRI 1007933, Aging Assessment Field Guide will be used as an aid during the inspection process.

Final Response: The reference in the System Condition Monitoring Program to, "civil structures" includes concrete local to component supports.

The MNGP System Walkdown Guidelines and Conduct of System Engineering work instructions are implementing procedures for the System Condition Monitoring Program. These procedures will be enhanced to include parameters inspected for concrete at locations of expansion and grouted anchors and grout pads for support base plates. EPRI 1007933, Aging Assessment Field Guide will be used as an aid during the inspection process.

Audit Question No.: B2.1.31-08

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Traiforos **MNGP Owner:** Madalin O'Brien **Discipline:** Civil

Question:

8. Water-Control Structures

- Is MNGP committed to RG 1.127?

- In LRA it is stated that the only water-control structure in scope for license renewal is the Intake Structure. The intake structure is described in Section 2.4.8 of the LRA. The NUREG-1801 description of AMP XI.S7 states that water-control structures covered by the RG 1.127 program include concrete structures; embankment structures; spillway structures and outlet works; reservoirs; cooling water channels and canals, and intake and discharge structures; and safety and performance instrumentation. Please explain briefly why only the intake structure (in fact portions of it) is within the scope of the LRA.

- According to the LRA, the Diesel Fire Pump House is located on top of the intake structure at the east end. The pump house has experienced some settlement over the years. How is settlement of the intake structure is monitored, trended and inspected?

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response:

MNGP is not committed to RG 1.127. Details for the water-control structures (NUREG-1801 XI.S7) are incorporated in the MNGP License Renewal Structures Monitoring Program 10 Attribute discussion.

MNGP does not have embankment structures, spillway structures and outlet works, reservoirs, cooling water channels and canals, discharge structures, and concrete structures other than the Intake Structure in scope of license renewal since only the Intake Structure has license renewal intended functions.

The Diesel Fire Pump House is located on the roof of the Intake Structure and has not experience settlement over the years. The Diesel Fuel Oil Transfer House, located just west of the Intake Structure, has experienced settlement. Annual settlement inspections of the Diesel Fuel Oil Transfer House are performed with comparison to an approved acceptance criteria. The Intake Structure is founded on a layer of cemented sandstone and monitoring of settlement is not required since no significant settlement has been observed on any major structure over the past 20 years.

Final Response:

MNGP is not committed to RG 1.127. Details for the water-control structures (NUREG-1801 XI.S7) are incorporated in the MNGP License Renewal Structures Monitoring Program 10 Attribute discussion.

MNGP does not have embankment structures, spillway structures and outlet works, reservoirs, cooling water channels and canals, discharge structures, and concrete structures other than the Intake Structure in scope of license renewal since only the Intake Structure has license renewal intended functions.

The Diesel Fire Pump House is located on the roof of the Intake Structure and has not experienced settlement over the years. The Diesel Fuel Oil Transfer House, located just west of the Intake Structure, has experienced settlement. Annual settlement inspections of the Diesel Fuel Oil Transfer House are performed with comparison to an approved acceptance criteria. The Intake Structure is founded on a layer of cemented sandstone and monitoring of settlement is not required since no significant settlement has been observed on any major structure over the past 20 years.

Audit Question No.: B2.1.1-01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Wen **MNGP Owner:** Madalin O'Brien **Discipline:** Civil

Question: B2.1.1 10 CFR 50, Appendix J Program

1. MNGP is under Appendix J Option B testing requirements, what are the current test intervals for Tape A, Type B, and Type C test? Is the Type A test presently on a 15-years test interval?

Date Received: 6/13/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - 2.1.1

Draft Response: 1. Interval Determination of Appendix J, Type A Test:
The Type A test, which is conducted at performance based intervals not exceeding 120 months (plus a possible 15 month extension to allow for refueling schedules) (see discussion for one-time basis that follows), challenges all postulated post-accident containment air leakage paths through the various components. The default interval between Type A tests is 48 months. This may be extended to 120 months following 2 consecutive tests with results that meet performance leakage acceptance criteria. The interval reverts to the default interval following a Type A test failure. As previously discussed, the current interval is extended to 15 years on a one-time basis.

Type A test requirements include visual examination of the containment exterior and interior to detect conditions that might adversely affect structural integrity or leak tightness. An examination is performed prior to each Type A test and between tests at nominal intervals of 40 months.

One-time basis for Type A Test:
The Type A test interval has been extended on a one-time basis to 15 years. The most recent test was performed in March of 1993. NEI 94-01 limits the interval between Type A tests to 120 months (with a possible 15 month extension if justified by refueling schedule changes). Therefore, per NEI 94-01, the subsequent test would have to be done no later than March of 2003. Following general industry practice, MNGP submitted a request for the one time interval extension to 15 years (Type A test no later than March 2008). This request was approved as documented in a 31 Mar 03 letter from L. M. Padovan of the NRC to D. L. Wilson of NMC. Technical Specification 6.8.M notes the extended interval.

Interval Determination of Appendix J, Type B Test:
Type B tests, which are conducted at performance based intervals not exceeding 120 months (plus an extension of 15 months if required by the refueling schedule), are performed to assess leakage through individual penetration isolation barriers other than valves.
NOTE: Per NEI 94-01, air lock tests must be performed at intervals not exceeding 30 months and at other times as determined by air lock use. Also, bolted access-way cover seals are always tested following end of outage closures of the access-ways.

The default interval between Type B tests is 30 months. The interval may be extended to 60 months following two (2) consecutive tests with results that meet performance leakage acceptance criteria and to 120 months following three (3) consecutive tests that meet these criteria. The interval reverts to the default interval following a test failure.

Interval Determination of Appendix J, Isolation Valve (Type C) Tests:
MNGP does not have a specific Containment Isolation Valve ISI Program. Containment isolation valve tests are based primarily on the Appendix J, Type C tests.

The Appendix J, Type C, Isolation Valve tests are conducted at performance based intervals not exceeding 60 months (plus an extension of 15 months if required by the refueling schedule). The default interval between Type C tests is 30 months and may be extended to 60 months following two (2) consecutive tests with results that meet performance leakage acceptance criteria. The interval reverts to the default following a test failure. Regulatory Guide 1.163 limits testing intervals to a maximum of 30 months for main steam, feed water, and containment purge isolation valves.

Final Response: 1. Interval Determination of Appendix J, Type A Test:
The Type A test, which is conducted at performance based intervals not exceeding 120 months (plus a possible 15 month extension to allow for refueling schedules) (see discussion for one-time basis that follows), challenges all postulated post-accident containment air leakage paths through the various components. The default interval

between Type A tests is 48 months. This may be extended to 120 months following 2 consecutive tests with results that meet performance leakage acceptance criteria. The interval reverts to the default interval following a Type A test failure. As previously discussed, the current interval is extended to 15 years on a one-time basis.

Type A test requirements include visual examination of the containment exterior and interior to detect conditions that might adversely affect structural integrity or leak tightness. An examination is performed prior to each Type A test and between tests at nominal intervals of 40 months.

One-time basis for Type A Test:
The Type A test interval has been extended on a one-time basis to 15 years. The most recent test was performed in March of 1993. NEI 94-01 limits the interval between Type A tests to 120 months (with a possible 15 month extension if justified by refueling schedule changes). Therefore, per NEI 94-01, the subsequent test would have to be done no later than March of 2003. Following general industry practice, MNGP submitted a request for the one time interval extension to 15 years (Type A test no later than March 2008). This request was approved as documented in a 31 Mar 03 letter from L. M. Padovan of the NRC to D. L. Wilson of NMC. Technical Specification 6.8.M notes the extended interval.

Interval Determination of Appendix J, Type B Test:
Type B tests, which are conducted at performance based intervals not exceeding 120 months (plus an extension of 15 months if required by the refueling schedule), are performed to assess leakage through individual penetration isolation barriers other than valves.
NOTE: Per NEI 94-01, air lock tests must be performed at intervals not exceeding 30 months and at other times as determined by air lock use. Also, bolted access-way cover seals are always tested following end of outage closures of the access-ways.

The default interval between Type B tests is 30 months. The interval may be extended to 60 months following two (2) consecutive tests with results that meet performance leakage acceptance criteria and to 120 months following three (3) consecutive tests that meet these criteria. The interval reverts to the default interval following a test failure.

Interval Determination of Appendix J, Isolation Valve (Type C) Tests:
MNGP does not have a specific Containment Isolation Valve ISI Program. Containment isolation valve tests are based primarily on the Appendix J, Type C tests.

The Appendix J, Type C, Isolation Valve tests are conducted at performance based intervals not exceeding 60 months (plus an extension of 15 months if required by the refueling schedule). The default interval between Type C tests is 30 months and may be extended to 60 months following two (2) consecutive tests with results that meet performance leakage acceptance criteria. The interval reverts to the default following a test failure. Regulatory Guide 1.163 limits testing intervals to a maximum of 30 months for main steam, feed water, and containment purge isolation valves.

Audit Question No.: B2.1.1-02

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Wen **MNGP Owner:** Madalin O'Brien **Discipline:** Civil

Question: B2.1.1 10 CFR 50, Appendix J Program

2. In additional to the required visual examination of accessible interior and exterior surface of the containment for evidence of structural degradation, the selection of Appendix J Option B, also requires performing 3 visual examinations in each 10-year period. How are these visual examinations scheduled and controlled in MNGP?

Date Received: 6/13/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - 2.1.1

Draft Response: 2. Appendix J, Option B, (3) Visual Examinations in Each 10-Year Period:
MNGP is committed in the USAR and Technical Specifications to following Option B.
Type A test requirements include visual examination of the containment exterior and interior to detect conditions that might adversely affect structural integrity or leak tightness. An examination is performed prior to each Type A test and between tests at nominal intervals of 40 months.

Final Response: 2. Appendix J, Option B, (3) Visual Examinations in Each 10-Year Period:
MNGP is committed in the USAR and Technical Specifications to following Option B.
Type A test requirements include visual examination of the containment exterior and interior to detect conditions that might adversely affect structural integrity or leak tightness. An examination is performed prior to each Type A test and between tests at nominal intervals of 40 months.

Audit Question No.: B2.1.1-03

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Wen **MNGP Owner:** Madalin O'Brien **Discipline:** Civil

Question: B2.1.1 10 CFR 50, Appendix J Program

3. How were testing intervals determined for the containment isolation valves? Are they based on the Appendix J Type C test program or Containment Isolation Valve ISI program, or both programs?

Date Received: 6/13/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: 3. Scope of Appendix J, Isolation Valve (Type C) Tests:
Isolation valve internals (i.e. seat, stem packing) are active components and therefore screened out for license renewal. Isolation valve bonnet gaskets and in-line flanges (within the test boundary) are passive components and therefore screened in for license renewal and require an aging management review. Appendix J, Isolation Valve (Type C) Tests are performed for leakage past containment isolation bonnet and in-line flanges.

The statement in PBD/AMP-025, (i.e.10CFR50, Appendix J Program) on page 12 may lead one to believe that valve bonnet gaskets and in-line flanges as well as the valve seat and stem packing are active and therefore screened out for license renewal. This is not the case. The intent of the statement was only to reaffirm that valve seat and stem packing are screened out. The statement from PBD/AMP-025 in question reads as follows, and is provided here for reference only.

> Isolation valves are active components and are, therefore, outside the scope of the aging management program.

Final Response: 3. Scope of Appendix J, Isolation Valve (Type C) Tests:
Isolation valve internals (i.e. seat, stem packing) are active components and therefore screened out for license renewal. Isolation valve bonnet gaskets and in-line flanges (within the test boundary) are passive components and therefore screened in for license renewal and require an aging management review. Appendix J, Isolation Valve (Type C) Tests are performed for leakage past containment isolation bonnet and in-line flanges.

The statement in PBD/AMP-025, (i.e.10CFR50, Appendix J Program) on page 12 may lead one to believe that valve bonnet gaskets and in-line flanges as well as the valve seat and stem packing are active and therefore screened out for license renewal. This is not the case. The intent of the statement was only to reaffirm that valve seat and stem packing are screened out. The statement from PBD/AMP-025 in question reads as follows, and is provided here for reference only.

> Isolation valves are active components and are, therefore, outside the scope of the aging management program.

Audit Question No.: B2.1.1-04

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Wen **MNGP Owner:** Madalin O'Brien **Discipline:** Civil

Question: B2.1.1 10 CFR 50, Appendix J Program

4. Have MNGP ever conducted a self-assessment of the containment leak rate test program to confirm the compliance with regulatory criteria and evaluate the need for improvement to the program? Verbal follow-up question as follows: Elaborate on the operating experience for the electrical penetration and core spray penetration found on page 28 of the AMP. Electrical Penetration JX-105A Conductor Seal Leak
- Work Request Authorization 87-04365
- Work Request Authorization 87-04427
Core Spray Penetration X-16B Expansion Bellows Leak
- Modification Package MP-97Q050

Date Received: 6/13/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - 2.1.1

Draft Response: The hard copies of the following have been provided on 6-16-05 (12 noon) - Work Request Authorization 87-04365,
-Work Request Authorization 87-04427, Modification Package MP-97Q050 (in part) , and Nuclear Oversight Observation Report dated 9-30-02 on the 10 CFR Appendix J Program.

Final Response: The hard copies were provided on 6-16-05 (12 noon) of Work Request Authorizations, Modification Package, and Nuclear Oversight Observation Report concerning 10 CFR Appendix J Program cited in the question for review by the NRC auditor.

Audit Question No.: B2.1.1-05

Source: **AMP Audit** **Status:** **Sufficient per NRC** **Author:** **Wen** **MNGP Owner:** **Madalin O'Brien** **Discipline:** **Programs**

Question: Question on B2.1.1 10 CFR50, Appendix J Program (Wen)

1. Please list MNGP procedures that are being used for the implementation of Appendix J leak rate test program, including Type A, B and C tests.

Date Received: 7/20/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - B2.1.1

Draft Response: Response to B2.1.1-05

Implementing documents/procedures for the MNGP 10 CFR 50 Appendix J Program obtained from Section 7.3 of PBD/AMP-025, include:
EWI-08.06.01, Primary Containment Leakage Rate Testing Program
Procedure 0136, Integrated Primary Containment Leak Rate Test
Procedure 0137, Master Local Leak Rate Test
Procedure 0138, Drywell Personnel Airlock Pressure and Leak Test
Procedure 0135, Pressure-Suppression Chamber Painted Surface Internal Inspection
Procedure 0140, Drywell Interior Surface Inspection
Procedure 0446-B, Type B and C Combined Leakage Check
Procedure 0515, Primary Containment Visual Examination for Structural Problems
Procedure 4320-PM, Drywell Penetration Airlock
Procedure 8080, Primary Containment Hatch Closure

Final Response: Implementation of the Appendix J Leak Rate Test Program will be accomplished by MNGP implementing documents and procedures, i.e., engineering work instructions, surveillance procedures, preventive maintenance procedures, and work control procedures.

Audit Question No.: B2.1.19-01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Wen **MNGP Owner:** Joe Pairitz **Discipline:** Mechanical

Question: 1. How is the minimum allowable wall thickness defined in MNGP FAC program?

Date Received: 6/7/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: IAW Program Engineering Fleet Procedure FP-PE-FAC-01, Revision 1, Flow Accelerated Corrosion Inspection Program (Section 5.6.6), if the wall thickness attributed to FAC is less than 60% of pipe nominal wall (applicable to non-safety related "Non-Class" piping) or 87.5% of nominal wall, applicable to safety-related "Class" piping), the piping shall have an Engineering Analysis performed in accordance with the site-specific Engineering Analysis procedure. (Note: The trigger on the calculation spreadsheet is set at .875 which shall be further discussed below). This evaluation will determine if the degraded component is acceptable for continued use. If the Engineering Analysis determines that a component requires repair or replacement during the inspection outage, a Condition Report (CR)/Action Request (AR) shall be initiated in accordance with the site-specific Corrective Action Program. If a planned replacement is required for the next refueling outage, a Work Request (WR) shall be initiated in accordance with the site-specific Processing Work Requests/Work Orders Program.

Section 5.17.1 of this same procedure also states that the predicted thickness of a component at next outage shall be greater than or equal to minimum acceptable wall thickness (Tcrit). Any component that falls below the acceptance criteria requires an Engineering Analysis to be performed per the site-specific procedures.

The remaining life for each inspected component is calculated as part of the initial component evaluation. This assessment is the remaining time until the reduction in component wall thickness due to wear reaches the minimum wall thickness or as determined by a specific Engineering Analysis for the component.

The remaining life calculated in the FAC component evaluation shall be utilized to determine when the component will require reinspection. The component shall be reinspected not later than the outage prior to the point at which the calculated minimum wall is reached. After a component is reinspected, a new remaining life shall be calculated and the component shall be reevaluated for future inspection or replacement. If system conditions appear to have changed in such a way as to increase wear rates or subsequent reinspection indicate wear rates significantly higher than previously predicted, consideration should be given to conducting reinspections at an increased frequency.

CAP CAP000532 (excerpts below) dated March 24, 2005 was written to evaluate the 60% of pipe nominal wall (applicable to non-safety related "Non-Class" piping) vs. 87.5% of nominal wall, applicable to safety-related "Class" piping with the following results:

Evaluation:

Section 5.6.6 of the fleet procedure for acceptance of flow accelerated corrosion defines two categories of piping. The second (which is not in question) is the use of 87.5% of the nominal wall thickness for ASME code class piping. This acceptance criteria is established as a result of mil spec tolerances for piping where the piping is considered acceptable per the mil specification if the wall thickness is 87.5% of nominal wall thickness.

However, other acceptance criteria established in section 5.6.6 is associated with non-ASME code class piping. The criteria established are 60% of nominal wall thickness before an engineering analysis is required. Implicit to this section is that hoop stress is not governing at this point. In other words, if the hoop stress defined minimum wall thickness is in excess of 60% of the nominal wall thickness, the hoop stress will define the need for an engineering analysis of the piping. Implicit to this discussion is the use of a remaining life assessment of the component as defined in sections 5.11 and 5.12. The remaining life of a component needs to be determined at the time of inspection to determine if the component will have a remaining life that exceeds a period where another inspection can occur (i.e. next outage).

The basis for the 60% of nominal wall thickness is associated with an engineering study performed by Vectra under contract for Common Wealth Edison. The study details evaluation of piping associated with Non- ASME code class designed to B.31.1 1967 Edition. The study defines statistical probabilities associated with the ratio of Thoop/Tnom. It was noted in the study that of the total population of components investigated (1113 random components). From the population, 355 components had a Thoop/Tnom ratio. The fraction of those components where Taxial governed the stress condition was 0.0%. The existence of zero statistical failures for the population with

Thoop/Tnom ratio of 0.55 and greater does not in itself guarantee that piping Taxial does not govern in all cases. However, the statistical inferences that can be made from this population of data was made. That statistical analysis determined that, for piping whose ratio of Thoop/Tnom ratio of 0.55 and greater, there is up to 1.1% (established with a 95% confidence interval) chance that the minimum pipe wall thickness is governed by the axial loads rather than the hoop stresses.

The study also determines the effects of the pipe wall thinning relative to axial stresses governing the minimum wall thickness. The worst-case scenario of 0.55 Tnom wall thickness was considered bounding. The maximum amount of overstress that could be encountered in this condition was 82%. ASME philosophy allows the use of an allowable stress of 1.8Sh for service level C components. Since an allowable stress of 1.8Sh is allowed, it is evident that this stress level will not cause piping failure. Furthermore, 1.8Sh is less than 0.5Su and the failure being evaluated is a bending failure the line would hinge rather than catastrophically fail. Lastly, strain hardening and plastic section modulus will serve to increase the capacity of the pipe. Therefore, for the possibility of the 1.1% population where axial stresses determine Tmin, the maximum overstress will be 82% and will not lead to a pipe failure.

Application of the acceptance criteria established in the NMC fleet procedure FP-PE-FAC-01 Section 5.6.6 of 0.60Tnom results in an overstress condition of 66% using the methodology described above. Thus the allowable stress of 1.8Sh will not be encountered by using the 0.6Tnom and piping failure in its bending mode should not be encountered.

Therefore, fleet procedure FP-PE-FAC-01 as written is satisfactory for the acceptance criteria for non-ASME code piping. The fleet procedure as written will prevent piping from experiencing an unanalyzed overstress condition in the hoop stresses and in the axial stresses. The use of the 60% Tnom will not open the plants to excessive risk in that (with a 95% confidence) there is a less than a 1.1% probability that a pipe whose Thoop is greater 60% of Tnom will have its Tmin defined by the axial stresses. Furthermore if piping degradation is observed in postulated 1.1% of piping whose axial stresses govern the definition of Tmin, using a 60% Tnom acceptance criteria will ensure that the service level C stress conditions (1.8Sh) of the ASME code will not be violated with 17.5% margin.

This demonstrates that the technical basis for utilizing the 60% of the nominal thickness for non-safety related piping as a trigger point for an engineering analysis can be justified from a statistical analysis standpoint. However, no situation specific analysis has been conducted to ensure the use of 60% of the nominal thickness for non-safety related piping as a trigger point for an engineering analysis for all cases at each station to confirm the fleet procedure in all cases has been conducted.

Conclusion:

Since a site specific engineering analysis for all cases at each station has not been conducted, the use of 60% of the nominal thickness for non-safety related piping as a trigger point for an engineering analysis, can only be statistically demonstrated to be acceptable. Therefore, the fleet procedure FP-PE-FAC-01, Flow Accelerated Corrosion Inspection Program, will be revised to use the industry accepted 87.5% of the nominal thickness for non-safety related piping as a trigger point for an engineering analysis.

This trigger point has been incorporated in FP-PE-FAC-01, Flow Accelerated Corrosion Inspection Program, as discussed in the first paragraph of this response.

Final Response: In accordance with the NMC program engineering fleet procedure for the Flow Accelerated Corrosion inspection program, if the wall thickness attributed to FAC is less than 60% of pipe nominal wall (applicable to non-safety related "Non-Class" piping) or 87.5% of nominal wall, applicable to safety-related "Class" piping), the piping shall have an Engineering Analysis performed in accordance with the site-specific Engineering Analysis procedure. (Note: The trigger on the calculation spreadsheet is set at .875 which shall be further discussed below). This evaluation will determine if the degraded component is acceptable for continued use. If the Engineering Analysis determines that a component requires repair or replacement during the inspection outage, a Condition Report (CR)/Action Request (AR) shall be initiated in accordance with the site-specific Corrective Action Program. If a planned replacement is required for the next refueling outage, a Work Request (WR) shall be initiated in accordance with the site-specific process for Work Requests/Work Orders.

NMC program engineering fleet procedure for the Flow Accelerated Corrosion inspection program also states that the predicted thickness of a component at next outage shall be greater than or equal to minimum acceptable wall thickness (Tcrit). Any component that falls below the acceptance criteria requires an Engineering Analysis to be performed per the site-specific procedures.

The remaining life for each inspected component is calculated as part of the initial component evaluation. This assessment is the remaining time until the reduction in component wall thickness due to wear reaches the minimum wall thickness or as determined by a specific Engineering Analysis for the component.

The remaining life calculated in the FAC component evaluation shall be utilized to determine when the component will require reinspection. The component shall be reinspected not later than the outage prior to the point at which the calculated minimum wall is reached. After a component is reinspected, a new remaining life shall be calculated and the component shall be reevaluated for future inspection or replacement. If system conditions appear to have changed in such a way as to increase wear rates or subsequent reinspection indicate wear rates significantly higher than previously predicted, consideration should be given to conducting reinspections at an increased frequency.

An NMC Fleet Corrective Action Program item (excerpts below) dated March 24, 2005 was written to evaluate the 60% of pipe nominal wall (applicable to non-safety related "Non-Class" piping) vs. 87.5% of nominal wall, applicable to safety-related "Class" piping with the following results:

Evaluation:

The section of the fleet procedure for acceptance of flow accelerated corrosion defines two categories of piping. The second (which is not in question) is the use of 87.5% of the nominal wall thickness for ASME code class piping. This acceptance criteria is established as a result of mil spec tolerances for piping where the piping is considered acceptable per the mil specification if the wall thickness is 87.5% of nominal wall thickness.

However, other acceptance criteria established in the fleet procedure associated with non-ASME code class piping. The criteria established are 60% of nominal wall thickness before an engineering analysis is required. Implicit to this section is that hoop stress is not governing at this point. In other words, if the hoop stress defined minimum wall thickness is in excess of 60% of the nominal wall thickness, the hoop stress will define the need for an engineering analysis of the piping. Implicit to this discussion is the use of a remaining life assessment of the component as defined in the fleet procedure. The remaining life of a component needs to be determined at the time of inspection to determine if the component will have a remaining life that exceeds a period where another inspection can occur (i.e. next outage).

The basis for the 60% of nominal wall thickness is associated with an industry engineering study. The study details evaluation of piping associated with Non- ASME code class designed to B.31.1 1967 Edition. The study defines statistical probabilities associated with the ratio of Thoop/Tnom. It was noted in the study that of the total population of components investigated (1113 random components). From the population, 355 components had a Thoop/Tnom ratio. The fraction of those components where Taxial governed the stress condition was 0.0%. The existence of zero statistical failures for the population with Thoop/Tnom ratio of 0.55 and greater does not in itself guarantee that piping Taxial does not govern in all cases. However, the statistical inferences that can be made from this population of data was made. That statistical analysis determined that, for piping whose ratio of Thoop/Tnom ratio of 0.55 and greater, there is up to 1.1% (established with a 95% confidence interval) chance that the minimum pipe wall thickness is governed by the axial loads rather than the hoop stresses.

The study also determines the effects of the pipe wall thinning relative to axial stresses governing the minimum wall thickness. The worst-case scenario of 0.55 Tnom wall thickness was considered bounding. The maximum amount of overstress that could be encountered in this condition was 82%. ASME philosophy allows the use of an allowable stress of 1.8Sh for service level C components. Since an allowable stress of 1.8Sh is allowed, it is evident that this stress level will not cause piping failure. Furthermore, 1.8Sh is less than 0.5Su and the failure being evaluated is a bending failure the line would hinge rather than catastrophically fail. Lastly, strain hardening and plastic section modulus will serve to increase the capacity of the pipe. Therefore, for the possibility of the 1.1% population where axial stresses determine Tmin, the maximum overstress will be 82% and will not lead to a pipe failure.

Application of the acceptance criteria established in the NMC fleet procedure for the Flow Accelerated Corrosion inspection program of 0.60Tnom results in an overstress condition of 66% using the methodology described above. Thus the allowable stress of 1.8Sh will not be encountered by using the 0.6Tnom and piping failure in its bending mode should not be encountered.

Therefore, the NMC fleet procedure for the Flow Accelerated Corrosion inspection program as written is satisfactory for the acceptance criteria for non-ASME code piping. The fleet procedure as written will prevent piping from experiencing an unanalyzed overstress condition in the hoop stresses and in the axial stresses. The use of the 60% Tnom will not open the plants to excessive risk in that (with a 95% confidence) there is a less than a 1.1% probability that a pipe whose Thoop is greater 60% of Tnom will have its Tmin defined by the axial stresses. Furthermore if piping degradation is observed in postulated 1.1% of piping whose axial stresses govern the definition of Tmin, using a 60% Tnom acceptance criteria will ensure that the service level C stress conditions (1.8Sh) of the ASME code will not be violated with 17.5% margin.

This demonstrates that the technical basis for utilizing the 60% of the nominal thickness for non-safety related piping as a trigger point for an engineering analysis can be justified from a statistical analysis standpoint. However, no situation specific analysis has been conducted to ensure the use of 60% of the nominal thickness for non-safety related piping as a trigger point for an engineering analysis for all cases at each station to confirm the fleet procedure in all cases has been conducted.

Conclusion:

Since a site specific engineering analysis for all cases at each station has not been conducted, the use of 60% of the nominal thickness for non-safety related piping as a trigger point for an engineering analysis, can only be statistically demonstrated to be acceptable. Therefore, the fleet procedure for the Flow Accelerated Corrosion inspection program, will be revised to use the industry accepted 87.5% of the nominal thickness for non-safety related piping as a trigger point for an engineering analysis.

This trigger point of 87.5% of the nominal thickness for non-safety related piping will be incorporated in NMC fleet procedure for the Flow Accelerated Corrosion inspection program, in the next revision of this document. MNGP will ensure that the trigger point is stated in the implementing documents that are tracked as part of the RAI database for incorporation and closure.

Audit Question No.: B2.1.19-02

Source: **AMP Audit** **Status:** **Sufficient per NRC** **Author:** **Wen** **MNGP Owner:** **Bill Roman** **Discipline:** **Mechanical**

Question: 2. If degradation is detected such that the measured wall thickness is less than the minimum predicted thickness, explain how the sample size is increased to bound the thinning for the same inspection period. Does MNGP's FAC program follow the recommendations provided in EPRI NSAC-202L-R2?

Date Received: 6/7/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: If wall thickness is less than the minimum allowable as defined in the response to Draft RAI B2.1.19-01, the sample size shall be expanded. The expansion will include a minimum of the next two most susceptible components in that CHECWORKS line, any component within two pipe diameters downstream (upstream if expander) or like components in parallel trains. If expansion finds additional components with significant FAC wear, the examinations will be expanded further. This does not apply if the thin area is determined to be weld prep.

The MNGP FAC Program does follow the recommendations provided in EPRI NSAC-202L-R2.
JPP 6/10/05

Final Response: If wall thickness is less than the minimum allowable as defined in the response to AMP Audit question number RAI B2.1.19-01, the sample size shall be expanded. The expansion will include a minimum of the next two most susceptible components in that CHECWORKS line, any component within two pipe diameters downstream (upstream if expander) or like components in parallel trains. If expansion finds additional components with significant FAC wear, the examinations will be expanded further. This does not apply if the thin area is determined to be weld prep.

The MNGP FAC Program does follow the recommendations provided in EPRI NSAC-202L-R2.

Audit Question No.: B2.1.19-03

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Wen **MNGP Owner:** Bill Roman **Discipline:** Mechanical

Question:

3. Describe the experience of FAC program at MNGP and the ability of the inspection programs to detect wall thinning in a timely manner before the intended function of piping components has been lost:

- Have components been identified that did not meet the minimum allowable wall thickness prior to replacement or loss of pressure retaining capacity?

- What corrective actions have been taken, and to what extent have these measures been effective in eliminating or reducing the wall thinning?

- What changes to the program have occurred to ensure that aging effects due to FAC have been successfully managed?

- Provide evidence that the current aging management program has been effective to successfully mitigate and detect wall thinning during the time period addressed by the LRA.

- Describe MNGP review of industry FAC experience which may not included in the NRC generic communications? Does the recent piping failure event at Japan Mihama Power Station Unit 3 on August 9, 2004, include in the MNGP's operating experience evaluation?

Date Received: 6/7/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response:

The Flow-Accelerated Corrosion Program manages aging effects (loss of material) due to flow-accelerated corrosion (FAC) on the internal surfaces of carbon or low alloy steel piping, elbows, reducers, expanders, and valve bodies which contain high energy fluids (both single phase and two phase). The Flow-Accelerated Corrosion Program has been effective in managing aging effects. Wall thinning problems in single-phase systems have occurred throughout the industry in feedwater and condensate systems, and in two-phase piping in extraction steam lines and moisture separator reheater and feedwater heater drains. Application of the program at MNGP has resulted in the identification and replacement of susceptible piping sections with materials more resistant to flow accelerated corrosion (e.g., extraction steam system piping and piping downstream of the moisture separators). The FAC Program was originally outlined in NUREG-1344 and implemented through GL 89-08, Erosion/Corrosion Induced Pipe Wall Thinning. The MNGP program has evolved through industry experience and is now implemented using the guidelines of EPRI NSAC-202L-R2 and CHECWORKS as a predictive tool. Included in the program are (a) an analysis to determine FAC susceptible locations; (b) performance of limited baseline inspections; (c) follow-up inspections to confirm the predictions; and (d) repairing or replacing components, as necessary. Monitoring locations and inspection methods have improved over time based on industry and plant-specific operating experience and through development of new and improved techniques. As an example, during a recent ultrasonic thickness survey of a torus cooling line, wall thinning was identified. Although this was attributed to cavitation and not FAC, the piping and associated valve will be replaced. Results of recent operating experience and a FAC Program assessment revealed no significant program deficiencies and support a conclusion that the FAC program effectively manages FAC in high-energy carbon steel piping and components.

First Bullet - Examination reports were reviewed from 1989 through 2005. No replacements as a result of minimum wall thickness being compromised were identified. However, extraction steam lines were replaced in the 1987 outage as a result of indications found during the 1987 outage. It is unknown from the historical records what the wall thickness was at the time of replacement. IAW the 1997-1998 examination report summary, the sections of piping associated with the 11(A&B), 12(A&B), and 13(A&B) feedwater heater vents were replaced as a result of FAC inspections. The piping diameters range from 3" to 8" depending on the components in question. The replacement need was discovered in 1997 and 1998 outages and subsequently replaced in either 1997 or 1998 (dependant upon the component in question). In most cases, the components were replaced with stainless steel to reduce the susceptibility to future degradation via the same mechanism.

Second Bullet - Typically the corrective actions taken have resulted in material replacement of susceptible piping sections with materials more resistant to flow accelerated corrosion. These corrective actions have been effective in either eliminating or reducing wall thinning. In some more recent replacements, additional operating time is required to properly evaluate the adequacy of these corrective actions.

In 1987, the extraction steam lines were found to be degrading due to FAC. As a corrective measure, significant portions of the extraction steam piping were replaced with

stainless steel during the 1987 outage. IAW the 2000 examination report summary, degradation was noted in the 14 (A&B) feedwater heaters. The degradation was identified in the region adjacent to the extraction steam inlet nozzles. As a result, further inspections were performed to determine the extent of the degradation. Once bounded, windows were cut in the heater shell. The eroded sections were repaired and lined with stainless steel to prevent degradation via the same mechanism. Various other components have been replaced as a result of wall thinning. Replacement with FAC resistant materials is considered as part of the actions taken to mitigate further issues when a component change as a result of wall thinning is identified.

Third Bullet - The primary changes to the program have been the incorporation of NMC Program Engineering Fleet Procedure FP-PE-FAC-01, Revision 1 (Flow Accelerated Corrosion Inspection Program), utilization of the EPRI developed CHECWORKS computer code and formalization of Industry OE into the Corrective Action Program, all to ensure that aging effects due to FAC are successfully managed.

In 2002 and 2003, MNGP converted to the CHECWORKS database for the trending and tracking of FAC inspections. With that conversion, MNGP also implements inspections and scoping in accordance with NSAC-202L that is the current industry guidance standard for the establishment of a FAC program.

Fourth Bullet - As stated in the second bullet above, application of the FAC Program at MNGP has resulted in the identification and replacement of susceptible piping sections with materials more resistant to flow accelerated corrosion (e.g., extraction steam system piping and piping downstream of the moisture separators). Monitoring locations and inspection methods have improved over time based on industry and plant-specific operating experience and through development of new and improved techniques. As an example, during a recent ultrasonic thickness survey of a torus cooling line, wall thinning was identified. Although this was attributed to cavitation and not FAC, the piping and associated valve will be replaced. Results of recent operating experience and a FAC Program assessment revealed no significant program deficiencies and support a conclusion that the FAC program effectively manages FAC in high-energy carbon steel piping and components.

As a result of inspections performed in almost all outages since 1989, replacements have occurred in either that current refueling outage or in subsequent refueling outages. Along with the identification of components needing replacement, appropriate scope expansion occurs to bound the thinning and determine the extent of replacement.

Fifth Bullet - Applicable Industry OE is evaluated through the corrective action process (Corrective Action Program) in addition to NRC generic communications. The recent piping failure event at Japan's Mihama Power Station Unit 3 on August 9, 2004, was included in the MNGP external operating experience (XOE) via the corrective action process and was included in the external (industry) operating experience IPA process review.

As a result of the incident at Mihama, MNGP included a larger portion than usual of the feedwater piping in its 2005 outage inspection scope. Furthermore, as a result of issues identified at the Quad Cities Nuclear Plant, MNGP also inspected portions of the reactor vessel bottom head drain piping demonstrating the effective implementation of OE. During the development of the CHECWORKS database in 2002, OE was reviewed and resulted in several components being added to the scope of the program. These are examples of the use of industry OE within the FAC Program that may not be included in NRC generic communications.

Final Response: The Flow-Accelerated Corrosion Program manages aging effects (loss of material) due to flow-accelerated corrosion (FAC) on the internal surfaces of carbon or low alloy steel piping, elbows, reducers, expanders, and valve bodies which contain high energy fluids (both single phase and two phase). The Flow-Accelerated Corrosion Program has been effective in managing aging effects. Wall thinning problems in single-phase systems have occurred throughout the industry in feedwater and condensate systems, and in two-phase piping in extraction steam lines and moisture separator reheater and feedwater heater drains. Application of the program at MNGP has resulted in the identification and replacement of susceptible piping sections with materials more resistant to flow accelerated corrosion (e.g., extraction steam system piping and piping downstream of the moisture separators). The FAC Program was originally outlined in NUREG-1344 and implemented through GL 89-08, Erosion/Corrosion Induced Pipe Wall Thinning. The MNGP program has evolved through industry experience and is now implemented using the guidelines of EPRI NSAC-202L-R2 and CHECWORKS as a predictive tool. Included in the program are (a) an analysis to determine FAC susceptible locations; (b) performance of limited baseline inspections; (c) follow-up inspections to confirm the predictions; and (d) repairing or replacing components, as necessary. Monitoring locations and inspection methods have improved over time based on industry and plant-specific operating experience and through development of new and improved techniques. As an example, during a recent ultrasonic thickness survey of a torus cooling line, wall thinning was identified. Although this was attributed to cavitation and not FAC, the piping and associated valve will be replaced. Results of recent operating experience and a FAC Program assessment revealed no significant program deficiencies and support a conclusion that the FAC program effectively manages FAC in high-energy carbon steel piping and components. The individual question bullets are further addressed below.

1. Concerning components that have been identified that did not meet the minimum allowable wall thickness, prior to replacement or loss of pressure retaining capacity;

examination reports were reviewed from 1989 through 2005. No replacements as a result of minimum wall thickness being compromised were identified. However, extraction steam lines were replaced in the 1987 outage as a result of indications found during the 1987 outage. It is unknown from the historical records what the wall thickness was at the time of replacement. IAW the 1997-1998 examination report summary, the sections of piping associated with the 11(A&B), 12(A&B), and 13(A&B) feedwater heater vents were replaced as a result of FAC inspections. The piping diameters range from 3" to 8" depending on the components in question. The replacement need was discovered in 1997 and 1998 outages and subsequently replaced in either 1997 or 1998 (dependant upon the component in question). In most cases, the components were replaced with stainless steel to reduce the susceptibility to future degradation via the same mechanism.

2. Concerning corrective actions taken, and to what extent these measures been effective in eliminating or reducing the wall thinning, typically the corrective actions taken have resulted in material replacement of susceptible piping sections with materials more resistant to flow accelerated corrosion. These corrective actions have been effective in either eliminating or reducing wall thinning. In some more recent replacements, additional operating time is required to properly evaluate the adequacy of these corrective actions.

In 1987, the extraction steam lines were found to be degrading due to FAC. As a corrective measure, significant portions of the extraction steam piping were replaced with stainless steel during the 1987 outage. IAW the 2000 examination report summary, degradation was noted in the 14 (A&B) feedwater heaters. The degradation was identified in the region adjacent to the extraction steam inlet nozzles. As a result, further inspections were performed to determine the extent of the degradation. Once bounded, windows were cut in the heater shell. The eroded sections were repaired and lined with stainless steel to prevent degradation via the same mechanism. Various other components have been replaced as a result of wall thinning. Replacement with FAC resistant materials is considered as part of the actions taken to mitigate further issues when a component change as a result of wall thinning is identified.

3. Concerning changes to the program that have occurred to ensure that aging effects due to FAC have been successfully managed, the primary changes to the program have been the incorporation of an NMC program engineering fleet procedure, utilization of the EPRI developed CHECWORKS computer code and formalization of Industry OE into the Corrective Action Program, all to ensure that aging effects due to FAC are successfully managed.

In 2002 and 2003, MNGP converted to the CHECWORKS database for the trending and tracking of FAC inspections. With that conversion, MNGP also implements inspections and scoping in accordance with NSAC-202L that is the current industry guidance standard for the establishment of a FAC program.

4. Concerning evidence that the current aging management program has been effective to successfully mitigate and detect wall thinning during the time period addressed by the LRA, as stated in the item 2 above, application of the FAC Program at MNGP has resulted in the identification and replacement of susceptible piping sections with materials more resistant to flow accelerated corrosion (e.g., extraction steam system piping and piping downstream of the moisture separators). Monitoring locations and inspection methods have improved over time based on industry and plant-specific operating experience and through development of new and improved techniques. As an example, during a recent ultrasonic thickness survey of a torus cooling line, wall thinning was identified. Although this was attributed to cavitation and not FAC, the piping and associated valve will be replaced. Results of recent operating experience and a FAC Program assessment revealed no significant program deficiencies and support a conclusion that the FAC program effectively manages FAC in high-energy carbon steel piping and components.

As a result of inspections performed in almost all outages since 1989, replacements have occurred in either that current refueling outage or in subsequent refueling outages. Along with the identification of components needing replacement, appropriate scope expansion occurs to bound the thinning and determine the extent of replacement.

5. Concerning the MNGP review of industry FAC experience which may not be included in the NRC generic communications and the recent piping failure event at Japan Mihama Power Station Unit 3 on August 9, 2004, applicable Industry OE is evaluated through the corrective action process (Corrective Action Program) in addition to NRC generic communications. The recent piping failure event at Japan's Mihama Power Station Unit 3 on August 9, 2004, was included in the MNGP external operating experience (XOE) via the corrective action process and was included in the external (industry) operating experience IPA process review.

As a result of the incident at Mihama, MNGP included a larger portion than usual of the feedwater piping in its 2005 outage inspection scope. Furthermore, as a result of issues identified at the Quad Cities Nuclear Plant, MNGP also inspected portions of the reactor vessel bottom head drain piping demonstrating the effective implementation of OE. During the development of the CHECWORKS database in 2002, OE was reviewed and resulted in several components being added to the scope of the program. These are examples of the use of industry OE within the FAC Program that may not be included in NRC generic communications.

Audit Question No.: B2.1.19-04

Source: **AMP Audit** **Status:** **Sufficient per NRC** **Author:** **Wen** **MNGP Owner:** **Bill Roman** **Discipline:** **Mechanical**

Question: The MNGP Program Basis Document PBD/AMP-002, Flow-Accelerated Corrosion Program, Table 7.1, only addresses carbon steel in the Item/Material column as a material susceptible to FAC. Is low alloy steel included in this category?

Date Received: 6/14/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Low-alloy steel is included in this category as stated in Section B2.1.19, Program Description, of the LRA as follows:

The Flow-Accelerated Corrosion Program manages aging effects (loss of material) due to flow-accelerated corrosion (FAC) on the internal surfaces of carbon or low-alloy steel piping, elbows, reducers, expanders, and valve bodies which contain high energy fluids (both single phase and two phase). The program implements the EPRI guidelines in NSAC-202L-R2. This program also requires the use of CHECWORKS as a predictive tool. Included in the program are (a) an analysis to determine FAC susceptible locations; (b) performance of limited baseline inspections; (c) follow-up inspections to confirm the predictions; and (d) repairing or replacing components, as necessary.

Low-alloy steel is also addressed in Section 3.1, Scope of Program, of the LRA.

The AMR Group in the License Renewal database (ALEX) for this material/environment combination is "Carbon Steel, Low-Alloy Steel and Cast Iron in Treated Water and/or Steam". Consequently, both carbon steel and low-alloy steel are addressed.

MNGP will ensure that both carbon steel and low-alloy-steel are stated in the implementing documents that are tracked as part of the RAI database for incorporation and closure.

Final Response: Low-alloy steel is included in this category as stated in Section B2.1.19, Program Description, of the LRA as follows:

The Flow-Accelerated Corrosion Program manages aging effects (loss of material) due to flow-accelerated corrosion (FAC) on the internal surfaces of carbon or low-alloy steel piping, elbows, reducers, expanders, and valve bodies which contain high energy fluids (both single phase and two phase). The program implements the EPRI guidelines in NSAC-202L-R2. This program also requires the use of CHECWORKS as a predictive tool. Included in the program are (a) an analysis to determine FAC susceptible locations; (b) performance of limited baseline inspections; (c) follow-up inspections to confirm the predictions; and (d) repairing or replacing components, as necessary.

Low-alloy steel is also addressed in Section B2.1.19, Scope of Program, of the LRA.

The AMR Group in the License Renewal database for this material/environment combination is Carbon Steel, Low-Alloy Steel and Cast Iron in Treated Water and/or Steam. Consequently, both carbon steel and low-alloy steel are addressed.

MNGP will ensure that both carbon steel and low-alloy-steel are stated in the implementing documents that are tracked as part of the RAI database for incorporation and closure.

Audit Question No.: B2.1.19-05

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Wen **MNGP Owner:** Jim Rootes **Discipline:** Programs

Question: Question on B2.1.19 FAC Program (Wen)

1. In MNGP's response to the previous audit question B2.1.19-01, MNGP stated that it will revise its procedure for the FAC inspection program to use the industry accepted 87.5% of the nominal pipe wall thickness for non safety-related piping as a trigger point for an engineering evaluation. Please confirm this commitment and list it in the MNGP LRA supplement.

Date Received: 7/20/2005 Potential Submittal on ☑ Potential LRA Update Required ☑ Assoc LRA Section - B2.1.19

Draft Response: The NMC fleet procedure will be revised to include the accepted 87.5% of nominal pipe wall thickness for non safety-related piping as a trigger point for engineering analysis. This action is entered and being tracked in the NMC corrective action process. The assigned due date for this action is 8/19/2005.

The commitment to revise this procedure will be listed in the MNGP LRA supplement.

This was discussed with D Musolf.

Final Response: The NMC fleet procedure will be revised to include the accepted 87.5% of nominal pipe wall thickness for non safety-related piping as a trigger point for engineering analysis. This action is entered and being tracked in the NMC corrective action process. The assigned due date for this action is 8/19/2005.

The commitment to revise this procedure will be listed in the MNGP LRA supplement.

Reviewed: DMM

Audit Question No.: B2.1.2-15

Source: **AMP Audit** **Status:** **Sufficient per NRC** **Author:** **Wen** **MNGP Owner:** **Bill O'Brien** **Discipline:** **Mechanical**

Question: On Monday, August 15, 2005 a telephone conference was held with the NRC. The NRC requested detailed summaries describing changes to the LRA, with respect to NRC Audit Item B2.1.26-01.

Date Received: 8/15/2005 Potential Submittal on ☐ Potential LRA Update Required ☑ Assoc LRA Section - Appendix B

Draft Response: Reference A: NMC letter to NRC, "Documentation of Responses to Aging Management Program and Aging Management Review Audits for the Monticello License Renewal Application (TAC No. MC6440)," dated August 11, 2005

ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD (NUREG-1801, XI.M1)

Alternatives Impacting AMP

The following MNGP ASME Section XI Program approved alternatives impact AMP B2.1.2:

·Alternative No. 1 - Risk Informed Inservice Inspection Plan
·Alternative No. 4 - Reactor Vessel Stabilizer Brackets
·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program
·Alternative No. 10 - Use of Code Case N-613-1
·Code Case N-307-2 - Revised Ultrasonic Examination Volume for Class I Bolting, Table IWB-2500-1, Examination Category B-G-1, When the examinations are conducted from the end of the bolt or stud, or from the center-drilled hole
·Code Case N-526 - Alternative Requirements for Successive Inspections of Class 1 and 2 Vessels

Justification for use of Alternatives

·Alternative No. 1 - Risk Informed Inservice Inspection Plan:

Monticello has implemented a Risk Informed Inservice Inspection (RI-ISI) Program for Class 1 and Class 2 piping welds. The RI-ISI program provides an alternative to the ASME Section XI, ISI requirements with regards to (1) the number of locations, (2) the locations of inspections, and (3) the method of inspection. The RI-ISI program maintains the fundamental requirements of ASME Section XI, such as the examination technique, examination frequency, and acceptance criteria. Although the RI-ISI program reduces the number of required examination locations, it maintains an acceptable level of quality and safety pursuant to 10CFR 50.55a(a)3, by focusing inspections on the most safety significant welds with nondestructive examination techniques that are more focused towards finding the types of expected aging effects as well as the types of flaws and degradation found during traditional inspections. The RI-ISI examinations result in improved detection of service-related degradations over those currently required by ASME Section XI. Therefore, the aging effect cracking continues to be adequately managed for the piping welds.

(Reference: Justification derived from the "Aging Management Discussion" section of Table 1 of Enclosure 1 of Reference A for the "Risk Informed Inservice Inspection Plan (Rev. 0)")

·Alternative No. 4 - Reactor Vessel Stabilizer Brackets:

As an alternative to the requirements of the ASME Section XI Code, Table IWB-2500-1, Category B-K, Item B10.10, MNGP performs a surface examination on the reactor pressure vessel stabilizer brackets if local (jet reaction forces) or seismic design loads are experienced. In addition, a VT-3 visual inspection of the accessible areas of all four

of the welded attachments was performed with no reportable indications. A release from the surface examination should have no effect on aging management of the reactor pressure vessel stabilizer brackets welds. The stabilizers brackets are not subject to general corrosion, stress corrosion cracking nor are they loaded so they are not subject to cumulative fatigue.

(Reference: Justification derived from the "Aging Management Discussion" section of Table 1 of Enclosure 1 of Reference A for the "Reactor Vessel Stabilizer Brackets (Rev. 0)".)

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program:

MNGP uses the 2001 Edition of Section XI in lieu of the 1995 Edition with the 1996 Addenda for repair/replacement activities. This alternative has already been generically reviewed and approved by the NRC staff for aging management of systems and components within the scope of license renewal.

(Reference: Justification derived from the "Aging Management Discussion" section of Table 1 of Enclosure 1 of Reference A for the "Use of 2001 Edition for Repair/ Replacement Program (Rev. 0)".)

·Alternative No. 10 - Use of Code Case N-613-1:

MNGP is required to perform inservice examinations of selected reactor vessel nozzle-to-vessel welds in accordance with the requirements ASME Section XI, Table IWB-2500-1, Examination Category B-D, Item No. B3.90. Figure IWB-2500-7(b) requires that a minimum volume of material, a distance of ts/2 (one half the reactor vessel shell thickness) adjacent to the weld, be examined. The required examination volume for the reactor vessel pressure retaining nozzle-to-vessel welds extends far beyond the weld into the base metal, and is unnecessarily large. The proposed alternative re-defined the examination volume boundary to 1/2 inch of base metal on each side of the widest portion of the weld, removing from examination the base metal that was extensively examined during prior inspections, and that is not in the high residual stress region associated with the weld. MNGP proposed the alternative described in the ASME Section XI Code Case N-613-1 in lieu of the ASME Section XI Table IWB-2500-1 Examination Category B3.90 requirements. This activity alters the examination volume boundary for the reactor vessel pressure retaining nozzle-to-vessel welds; however, the aging effect continues to be managed and inspected.

(Reference: Justification derived from the "Aging Management Discussion" section of Table 1 of Enclosure 1 of Reference A for the "Use of Code Case N-613-1 (Rev. 0)".)

·Code Case N-307-2 - Revised Ultrasonic Examination Volume for Class I Bolting, Table IWB-2500-1, Examination Category B-G-1, When the examinations are conducted from the end of the bolt or stud, or from the center-drilled hole:

MNGP utilizes a revised ultrasonic examination volume for Class I bolting, Table IWB-2500-1, Examination Category B-G-1, when the examinations are conducted from the end of the bolt or stud, or from the center-drilled hole. This alternative eliminates the examination of the center bore hole surface by allowing a surface examination of the OD surface or a volumetric examination of a cylindrical region 1/4 inch thick measured from the minor diameter of the bolt or stud. The only bolts with center holes are the reactor head closure studs and reactor recirculation pump bolts. This Code case changes the portion of the bolt being evaluated but should still identify the presence of relevant aging effects.

(Reference: Justification derived from the "Aging Management Discussion" section of Table 2 of Enclosure 1 of Reference A for "Code Case N-307-2".)

·Code Case N-526 - Alternative Requirements for Successive Inspections of Class 1 and 2 Vessels:

MNGP utilizes alternative requirements for successive inspections required by IWB-2420 and IWC-2420, when areas of the vessel are found, by volumetric examinations, to contain subsurface flaws. The successive inspections may be waived when the flaw is found to be acceptable for continued service in accordance with IWB-3600. The vessel aging effects continue to be managed and the flaws are still required to be acceptable for continued service. Therefore, there is no impact on aging management of the vessel.

(Reference: Justification derived from the "Aging Management Discussion" section of Table 2 of Enclosure 1 of Reference A for "Code Case N-526".)

LRA Changes

B2.1.2 ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD

Each of the above alternatives and the associated justification are added to the "Exceptions to NUREG-1801" subsection of the LRA for AMP B2.1.2 and to the appropriate AMP program element discussions. Further, the statement under the "NUREG-1801 Consistency" regarding "Exceptions to ASME Code requirements that have been granted by approved Code Cases or relief requests, or modifications by 10 CFR 50.55a are not considered to be exceptions to NUREG-1801 criteria." is removed. Also, the statement under the "Corrective Actions" regarding "and approved NRC relief requests" is removed.

Reactor Head Closure Studs (NUREG-1801, XI.M3)

Alternatives Impacting AMP

The following MNGP ASME Section XI Program approved alternatives impact AMP B2.1.28:

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program
·Code Case N-307-2 - Revised Ultrasonic Examination Volume for Class I Bolting, Table IWB-2500-1, Examination Category B-G-1, When the examinations are conducted from the end of the bolt or stud, or from the center-drilled hole

Justification for use of Alternatives

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program: The justification is identical to the ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD AMP.
·Code Case N-307-2 - Revised Ultrasonic Examination Volume for Class I Bolting, Table IWB-2500-1, Examination Category B-G-1, When the examinations are conducted from the end of the bolt or stud, or from the center-drilled hole: The justification is identical to the ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD AMP.

LRA Changes

B2.1.28 Reactor Head Closure Studs

Each of the above alternatives and the associated justification are added to the "Exceptions to NUREG-1801" subsection of the LRA for AMP B2.1.28 and to the appropriate AMP program element discussions. Further, the statement under the "NUREG-1801 Consistency" regarding "Exceptions to ASME requirements that have been granted by approved Code Cases or relief requests are not considered to be exceptions to NUREG-1801 criteria." is removed.

3.X.2 Table Changes

The Notes for the LRA 3.X.2 Tables, which reference the Reactor Head Closure Studs AMP, are changed from either Note A to Note B or Note C to Note D, to reflect the change in the status of the AMP from "AMP is consistent with NUREG-1801 AMP" to "AMP takes some exceptions to NUREG-1801 AMP".

BWR Vessel ID Attachment Welds (NUREG-1801, XI.M4)

Alternatives Impacting AMP

The following MNGP ASME Section XI Program approved alternatives impact AMP B2.1.11:

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program

Justification for use of Alternatives

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program: The justification is identical to the ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD AMP.

LRA Changes

A2.1.11 BWR Vessel ID Attachment Welds

The statement regarding "and approved ISI Relief Requests" is removed.

B2.1.11 BWR Vessel ID Attachment Welds

The above alternative and the associated justification is added to the "Exceptions to NUREG-1801" subsection of the LRA for AMP B2.1.11 and to the appropriate AMP program element discussions. Further, the statement under the "Program Description" regarding "and approved ISI Relief Requests" is removed.

BWR Feedwater Nozzle (NUREG-1801, XI.M5)

Alternatives Impacting AMP

The following MNGP ASME Section XI Program approved alternatives impact AMP B2.1.8:

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program

Justification for use of Alternatives

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program: The justification is identical to the ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD AMP.

LRA Changes

B2.1.8 BWR Feedwater Nozzle

The above alternative and the associated justification is added to the "Exceptions to NUREG-1801" subsection of the LRA for AMP B2.1.8 and to the appropriate AMP program element discussions.

3.X.2 Table Changes

The Notes for the LRA 3.X.2 Tables, which reference the BWR Feedwater Nozzle AMP, are changed from either Note A to Note B or Note C to Note D, to reflect the change in the status of the AMP from "AMP is consistent with NUREG-1801 AMP" to "AMP takes some exceptions to NUREG-1801 AMP".

BWR Control Rod Drive Return Line Nozzle (NUREG-1801, XI.M6)

Alternatives Impacting AMP

The following MNGP ASME Section XI Program approved alternatives impact AMP B2.1.7:

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program

Justification for use of Alternatives

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program: The justification is identical to the ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD AMP.

LRA Changes

B2.1.7 BWR Control Rod Drive Return Line Nozzle

The above alternative and the associated justification is added to the "Exceptions to NUREG-1801" subsection of the LRA for AMP B2.1.7 and to the appropriate AMP program element discussions.

BWR Stress Corrosion Cracking (NUREG-1801, XI.M7)

Alternatives Impacting AMP

The following MNGP ASME Section XI Program approved alternatives impact AMP B2.1.10:

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program

Justification for use of Alternatives

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program: The justification is identical to the ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD AMP.

LRA Changes

A2.1.10 BWR Stress Corrosion Cracking

The reference to the "Risk-Informed ISI Program" is removed.

B2.1.10 BWR Stress Corrosion Cracking

The above alternative and the associated justification is added to the "Exceptions to NUREG-1801" subsection of the LRA for AMP B2.1.10 and to the appropriate AMP program element discussions.

The reference to the "Risk-Informed ISI Program" is removed from the "Program Description" subsection of the LRA for AMP B2.1.10.

The reference to "and RI-ISI" is removed from the "Detection of Aging Effects" subsection of the LRA for AMP B2.1.10.

The reference to "and the RI-ISI Program" is removed from the "Monitoring and Trending" subsection of the LRA for AMP B2.1.10.

BWR Penetrations (NUREG-1801, XI.M8)

Alternatives Impacting AMP

The following MNGP ASME Section XI Program approved alternatives impact AMP B2.1.9:

·Alternative No. 1 - Risk Informed Inservice Inspection Plan
·Alternative No. 10 - Use of Code Case N-613-1

Justification for use of Alternatives

·Alternative No. 1 - Risk Informed Inservice Inspection Plan: The justification is identical to the ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD AMP.
·Alternative No. 10 - Use of Code Case N-613-1: The justification is identical to the ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD AMP.

LRA Changes

A2.1.9 BWR Penetrations

The statement regarding "with approved ISI Relief Requests" is removed.

B2.1.9 BWR Penetrations

Each of the above alternatives and the associated justification are added to the "Exceptions to NUREG-1801" subsection of the LRA for AMP B2.1.9 and to the appropriate AMP program element discussions. Further, the statement under the "Program Description" regarding "with approved ISI Relief Requests" is removed.

BWR Vessel Internals (NUREG-1801, XI.M9)

Alternatives Impacting AMP

·None

Justification for use of Alternatives

·Not Applicable

LRA Changes

A2.1.12 BWR Vessel Internals

The statement regarding "and approved ISI Relief Requests" is removed.

B2.1.12 BWR Vessel Internals

The statement under the "Program Description" regarding "and approved ISI Relief Requests" is removed.

Thermal Aging And Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) (NUREG-1801, XI.M13)

Alternatives Impacting AMP

The following MNGP ASME Section XI Program approved alternatives impact AMP B2.1.33:

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program

Justification for use of Alternatives

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program: The justification is identical to the ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD AMP.

LRA Changes

B2.1.33 Thermal Aging & Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)

The above alternative and the associated justification is added to the "Exceptions to NUREG-1801" subsection of the LRA for AMP B2.1.33 and to the appropriate AMP program element discussions.

3.X.2 Table Changes

The Notes for the LRA 3.X.2 Tables, which reference the Thermal Aging & Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) AMP, are changed from either Note A to Note B or Note C to Note D, to reflect the change in the status of the AMP from "AMP is consistent with NUREG-1801 AMP" to "AMP takes some exceptions to NUREG-1801 AMP".

Bolting Integrity (NUREG-1801, XI.M18)

Alternatives Impacting AMP

The following MNGP ASME Section XI Program approved alternatives impact AMP B2.1.4:

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program

Justification for use of Alternatives

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program: The justification is identical to the ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD AMP.

LRA Changes

B2.1.4 Bolting Integrity

The above alternative and the associated justification is added to the "Exceptions to NUREG-1801" subsection of the LRA for AMP B2.1.4 and to the appropriate AMP program element discussions. Further, the statement under the "Detection of Aging Effects" regarding "except as allowed by code cases, relief requests, or interpretations" is removed. Also, the statement under the "Corrective Actions" regarding "per a previously approved ISI Relief Request" is removed.

The reference to the "risk-informed methodology" is removed from the "Monitoring and Trending" subsection of the LRA for AMP B2.1.4.

3.X.2 Table Changes

The Notes for the LRA 3.X.2 Tables, which reference the Bolting Integrity AMP, are changed from either Note A to Note B or Note C to Note D, to reflect the change in the status of the AMP from "AMP is consistent with NUREG-1801 AMP" to "AMP takes some exceptions to NUREG-1801 AMP".

Primary Containment In-Service Inspection Program (NUREG-1801, XI.S1)

Alternatives Impacting AMP

·None

Justification for use of Alternatives

·Not Applicable

LRA Changes

B2.1.26 Primary Containment In-Service Inspection Program

The statement under the "NUREG-1801 Consistency" regarding "Exceptions to ASME Code requirements that have been granted by approved Code Cases or relief requests are not considered to be exceptions to NUREG-1801 criteria." is removed. The statement is not required. ASME Section XI, Subsection IWE alternatives expire prior to the period of extended operation.

The statement under the "Scope of Program" regarding "These are not considered exceptions since the MNGP program has been reviewed by the NRC and is in accordance with 10CFR50.55a with NRC approved relief requests." is removed. The statement is not required. ASME Section XI, Subsection IWE alternatives expire prior to the period of extended operation.

The statement under the "Parameters Monitored or Inspected" regarding "These are not considered exceptions since the MNGP program has been reviewed by the NRC and is in accordance with 10CFR50.55a with NRC approved relief requests." is removed. The statement is not required. ASME Section XI, Subsection IWE alternatives expire prior to the period of extended operation.

The statement under the "Detection of Aging Effects" regarding "This is not considered an exception since the MNGP program has been reviewed by the NRC and is in accordance with 10CFR50.55a with NRC approved relief requests." is removed. The statement is not required. ASME Section XI, Subsection IWE alternatives expire prior to the period of extended operation.

The statement under the "Monitoring and Trending" regarding "This is not considered an exception since the MNGP program has been reviewed by the NRC and is in accordance with 10CFR50.55a with NRC approved relief requests." is removed. The statement is not required. ASME Section XI, Subsection IWE alternatives expire prior to the period of extended operation.

The statement under the "Corrective Actions" regarding "This is not considered an exception since the MNGP program has been reviewed by the NRC and is in accordance with 10CFR50.55a with NRC approved relief requests." is removed. The statement is not required. ASME Section XI, Subsection IWE alternatives expire prior to the period of extended operation.

The statement under the "Confirmation Process" regarding "This is not considered an exception since the MNGP program has been reviewed by the NRC and is in accordance with 10CFR50.55a with NRC approved relief requests." is removed. The statement is not required. ASME Section XI, Subsection IWE alternatives expire prior to the period of extended operation.

ASME Section XI, Subsection IWF (NUREG-1801, XI.S3)

Alternatives Impacting AMP

The following MNGP ASME Section XI Program approved alternatives impact AMP B2.1.3:

·Code Case N-491-2 - Rules for Examination of Class 1, 2, 3, and MC Component Supports of Light-Water Cooled Power Plants, Section XI, Division 1

Justification for use of Alternatives

·Code Case N-491-2 - Rules for Examination of Class 1, 2, 3, and MC Component Supports of Light-Water Cooled Power Plants, Section XI, Division 1:

MNGP allows for corrective measures to be performed on a component support to return the support to its design condition after acceptance by evaluation or test, without requiring additional examinations. This alternative involves corrective actions of component supports and has no impact on the aging management of the supports.

(Reference: Justification is derived from the "Aging Management Discussion" section of Table 2 of Enclosure 1 of Reference A for the "Code Case N-491-2".)

LRA Changes

B2.1.3 ASME Section XI, Subsection IWF

The above alternative and the associated justification is added to the "Exceptions to NUREG-1801" subsection of the LRA for AMP B2.1.3 and to the appropriate AMP program element discussions.

3.X.2 Table Changes

The Notes for the LRA 3.X.2 Tables, which reference the ASME Section XI, Subsection IWF AMP, are changed from either Note A to Note B or Note C to Note D, to reflect the change in the status of the AMP from "AMP is consistent with NUREG-1801 AMP" to "AMP takes some exceptions to NUREG-1801 AMP".

Final Response: Reference A: NMC letter to NRC, "Documentation of Responses to Aging Management Program and Aging Management Review Audits for the Monticello License Renewal Application (TAC No. MC6440)," dated August 11, 2005

ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD (NUREG-1801, XI.M1)

Alternatives Impacting AMP

The following MNGP ASME Section XI Program approved alternatives impact AMP B2.1.2:

·Alternative No. 1 - Risk Informed Inservice Inspection Plan
·Alternative No. 4 - Reactor Vessel Stabilizer Brackets
·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program
·Alternative No. 10 - Use of Code Case N-613-1
·Code Case N-307-2 - Revised Ultrasonic Examination Volume for Class I Bolting, Table IWB-2500-1, Examination Category B-G-1, When the examinations are conducted from the end of the bolt or stud, or from the center-drilled hole
·Code Case N-526 - Alternative Requirements for Successive Inspections of Class 1 and 2 Vessels

Justification for use of Alternatives

·Alternative No. 1 - Risk Informed Inservice Inspection Plan:

Monticello has implemented a Risk Informed Inservice Inspection (RI-ISI) Program for Class 1 and Class 2 piping welds. The RI-ISI program provides an alternative to the ASME Section XI, ISI requirements with regards to (1) the number of locations, (2) the locations of inspections, and (3) the method of inspection. The RI-ISI program maintains the fundamental requirements of ASME Section XI, such as the examination technique, examination frequency, and acceptance criteria. Although the RI-ISI program reduces the number of required examination locations, it maintains an acceptable level of quality and safety pursuant to 10CFR 50.55a(a)3, by focusing inspections on the most safety significant welds with nondestructive examination techniques that are more focused towards finding the types of expected aging effects as well as the types of flaws and degradation found during traditional inspections. The RI-ISI examinations result in improved detection of service-related degradations over those currently required by ASME Section XI. Therefore, the aging effect cracking continues to be adequately managed for the piping welds.

(Reference: Justification derived from the "Aging Management Discussion" section of Table 1 of Enclosure 1 of Reference A for the "Risk Informed Inservice Inspection Plan (Rev. 0)")

·Alternative No. 4 - Reactor Vessel Stabilizer Brackets:

As an alternative to the requirements of the ASME Section XI Code, Table IWB-2500-1, Category B-K, Item B10.10, MNGP performs a surface examination on the reactor pressure vessel stabilizer brackets if local (jet reaction forces) or seismic design loads are experienced. In addition, a VT-3 visual inspection of the accessible areas of all four of the welded attachments was performed in 2005 with no reportable indications. A release from the surface examination should have no effect on aging management of the reactor pressure vessel stabilizer brackets welds. The stabilizers brackets are not subject to general corrosion or stress corrosion cracking, nor are they loaded so they are not subject to cumulative fatigue.

(Reference: Justification derived from the "Aging Management Discussion" section of Table 1 of Enclosure 1 of Reference A for the "Reactor Vessel Stabilizer Brackets (Rev. 0)".)

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program:

MNGP uses the 2001 Edition of Section XI in lieu of the 1995 Edition with the 1996 Addenda for repair/replacement activities. This alternative has already been generically reviewed and approved by the NRC staff for aging management of systems and components within the scope of license renewal.

(Reference: Justification derived from the "Aging Management Discussion" section of Table 1 of Enclosure 1 of Reference A for the "Use of 2001 Edition for Repair/ Replacement Program (Rev. 0)".)

·Alternative No. 10 - Use of Code Case N-613-1:

MNGP is required to perform inservice examinations of selected reactor vessel nozzle-to-vessel welds in accordance with the requirements ASME Section XI, Table IWB-2500-1, Examination Category B-D, Item No. B3.90. Figure IWB-2500-7(b) requires that a minimum volume of material, a distance of ts/2 (one half the reactor vessel shell thickness) adjacent to the weld, be examined. The required examination volume for the reactor vessel pressure retaining nozzle-to-vessel welds extends far beyond the weld into the base metal, and is unnecessarily large. The proposed alternative re-defined the examination volume boundary to 1/2 inch of base metal on each side of the widest portion of the weld, removing from examination the base metal that was extensively examined during prior inspections, and that is not in the high residual stress region associated with the weld. MNGP proposed the alternative described in the ASME Section XI Code Case N-613-1 in lieu of the ASME Section XI Table IWB-2500-1 Examination Category B3.90 requirements. This activity alters the examination volume boundary for the reactor vessel pressure retaining nozzle-to-vessel welds; however, the aging effect continues to be managed and inspected.

(Reference: Justification derived from the "Aging Management Discussion" section of Table 1 of Enclosure 1 of Reference A for the "Use of Code Case N-613-1 (Rev. 0)".)

·Code Case N-307-2 - Revised Ultrasonic Examination Volume for Class I Bolting, Table IWB-2500-1, Examination Category B-G-1, When the examinations are conducted from the end of the bolt or stud, or from the center-drilled hole:

MNGP utilizes a revised ultrasonic examination volume for Class I bolting, Table IWB-2500-1, Examination Category B-G-1, when the examinations are conducted from the end of the bolt or stud, or from the center-drilled hole. This alternative eliminates the examination of the center bore hole surface by allowing a surface examination of the OD surface or a volumetric examination of a cylindrical region 1/4 inch thick measured from the minor diameter of the bolt or stud. The only bolts with center holes are the reactor head closure studs and reactor recirculation pump bolts. This alternative changes the portion of the bolt being evaluated but should still identify the presence of relevant aging effects.

(Reference: Justification derived from the "Aging Management Discussion" section of Table 2 of Enclosure 1 of Reference A for "Code Case N-307-2".)

·Code Case N-526 - Alternative Requirements for Successive Inspections of Class 1 and 2 Vessels:

MNGP utilizes alternative requirements for successive inspections required by IWB-2420 and IWC-2420, when areas of the vessel are found, by volumetric examinations, to contain subsurface flaws. The successive inspections may be waived when the flaw is found to be acceptable for continued service in accordance with IWB-3600. The vessel aging effects continue to be managed and the flaws are still required to be acceptable for continued service. Therefore, there is no impact on aging management of the vessel.

(Reference: Justification derived from the "Aging Management Discussion" section of Table 2 of Enclosure 1 of Reference A for "Code Case N-526".)

LRA Changes

B2.1.2 ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD

Each of the above alternatives and the associated justification are added to the "Exceptions to NUREG-1801" subsection of the LRA for AMP B2.1.2 and to the appropriate AMP program element discussions. Further, the statement under the "NUREG-1801 Consistency" regarding "Exceptions to ASME Code requirements that have been granted by approved Code Cases or relief requests, or modifications by 10 CFR 50.55a are not considered to be exceptions to NUREG-1801 criteria." is removed. Also, the statement under the "Corrective Actions" regarding "and approved NRC relief requests" is removed.

Reactor Head Closure Studs (NUREG-1801, XI.M3)

Alternatives Impacting AMP

The following MNGP ASME Section XI Program approved alternatives impact AMP B2.1.28:

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program
·Code Case N-307-2 - Revised Ultrasonic Examination Volume for Class I Bolting, Table IWB-2500-1, Examination Category B-G-1, When the examinations are conducted from the end of the bolt or stud, or from the center-drilled hole

Justification for use of Alternatives

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program: The justification is identical to the ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD AMP.
·Code Case N-307-2 - Revised Ultrasonic Examination Volume for Class I Bolting, Table IWB-2500-1, Examination Category B-G-1, When the examinations are conducted from the end of the bolt or stud, or from the center-drilled hole: The justification is identical to the ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD AMP.

LRA Changes

B2.1.28 Reactor Head Closure Studs

Each of the above alternatives and the associated justification are added to the "Exceptions to NUREG-1801" subsection of the LRA for AMP B2.1.28 and to the appropriate AMP program element discussions. Further, the statement under the "NUREG-1801 Consistency" regarding "Exceptions to ASME requirements that have been granted by approved Code Cases or relief requests are not considered to be exceptions to NUREG-1801 criteria." is removed.

3.X.2 Table Changes

The Notes for the LRA 3.X.2 Tables, which reference the Reactor Head Closure Studs AMP, are changed from either Note A to Note B or Note C to Note D, to reflect the change in the status of the AMP from "AMP is consistent with NUREG-1801 AMP" to "AMP takes some exceptions to NUREG-1801 AMP".

BWR Vessel ID Attachment Welds (NUREG-1801, XI.M4)

Alternatives Impacting AMP

The following MNGP ASME Section XI Program approved alternatives impact AMP B2.1.11:

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program

Justification for use of Alternatives

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program: The justification is identical to the ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD AMP.

LRA Changes

A2.1.11 BWR Vessel ID Attachment Welds

The statement regarding "and approved ISI Relief Requests" is removed.

B2.1.11 BWR Vessel ID Attachment Welds

The above alternative and the associated justification are added to the "Exceptions to NUREG-1801" subsection of the LRA for AMP B2.1.11 and to the appropriate AMP program element discussions. Further, the statement under the "Program Description" regarding "and approved ISI Relief Requests" is removed.

BWR Feedwater Nozzle (NUREG-1801, XI.M5)

Alternatives Impacting AMP

The following MNGP ASME Section XI Program approved alternatives impact AMP B2.1.8:

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program

Justification for use of Alternatives

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program: The justification is identical to the ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD AMP.

LRA Changes

B2.1.8 BWR Feedwater Nozzle

The above alternative and the associated justification are added to the "Exceptions to NUREG-1801" subsection of the LRA for AMP B2.1.8 and to the appropriate AMP program element discussions.

3.X.2 Table Changes

The Notes for the LRA 3.X.2 Tables, which reference the BWR Feedwater Nozzle AMP, are changed from either Note A to Note B or Note C to Note D, to reflect the change in the status of the AMP from "AMP is consistent with NUREG-1801 AMP" to "AMP takes some exceptions to NUREG-1801 AMP".

BWR Control Rod Drive Return Line Nozzle (NUREG-1801, XI.M6)

Alternatives Impacting AMP

The following MNGP ASME Section XI Program approved alternatives impact AMP B2.1.7:

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program

Justification for use of Alternatives

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program: The justification is identical to the ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD AMP.

LRA Changes

B2.1.7 BWR Control Rod Drive Return Line Nozzle

The above alternative and the associated justification are added to the "Exceptions to NUREG-1801" subsection of the LRA for AMP B2.1.7 and to the appropriate AMP program element discussions.

BWR Stress Corrosion Cracking (NUREG-1801, XI.M7)

Alternatives Impacting AMP

The following MNGP ASME Section XI Program approved alternatives impact AMP B2.1.10:

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program

Justification for use of Alternatives

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program: The justification is identical to the ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD AMP.

LRA Changes

A2.1.10 BWR Stress Corrosion Cracking

The reference to the "Risk-Informed ISI Program" is removed.

B2.1.10 BWR Stress Corrosion Cracking

The above alternative and the associated justification are added to the "Exceptions to NUREG-1801" subsection of the LRA for AMP B2.1.10 and to the appropriate AMP program element discussions.

The reference to the "Risk-Informed ISI Program" is removed from the "Program Description" subsection of the LRA for AMP B2.1.10.

The reference to "and RI-ISI" is removed from the "Detection of Aging Effects" subsection of the LRA for AMP B2.1.10.

The reference to "and the RI-ISI Program" is removed from the "Monitoring and Trending" subsection of the LRA for AMP B2.1.10.

BWR Penetrations (NUREG-1801, XI.M8)

Alternatives Impacting AMP

The following MNGP ASME Section XI Program approved alternatives impact AMP B2.1.9:

·Alternative No. 1 - Risk Informed Inservice Inspection Plan
·Alternative No. 10 - Use of Code Case N-613-1

Justification for use of Alternatives

·Alternative No. 1 - Risk Informed Inservice Inspection Plan: The justification is identical to the ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD AMP.
·Alternative No. 10 - Use of Code Case N-613-1: The justification is identical to the ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD AMP.

LRA Changes

A2.1.9 BWR Penetrations

The statement regarding "with approved ISI Relief Requests" is removed.

B2.1.9 BWR Penetrations

Each of the above alternatives and the associated justification are added to the "Exceptions to NUREG-1801" subsection of the LRA for AMP B2.1.9 and to the appropriate AMP program element discussions. Further, the statement under the "Program Description" regarding "with approved ISI Relief Requests" is removed.

BWR Vessel Internals (NUREG-1801, XI.M9)

Alternatives Impacting AMP

·None

Justification for use of Alternatives

·Not Applicable

LRA Changes

A2.1.12 BWR Vessel Internals

The statement regarding "and approved ISI Relief Requests" is removed.

B2.1.12 BWR Vessel Internals

The statement under the "Program Description" regarding "and approved ISI Relief Requests" is removed.

Thermal Aging And Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) (NUREG-1801, XI.M13)

Alternatives Impacting AMP

The following MNGP ASME Section XI Program approved alternatives impact AMP B2.1.33:

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program

Justification for use of Alternatives

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program: The justification is identical to the ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD AMP.

LRA Changes

B2.1.33 Thermal Aging & Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)

The above alternative and the associated justification are added to the "Exceptions to NUREG-1801" subsection of the LRA for AMP B2.1.33 and to the appropriate AMP program element discussions.

3.X.2 Table Changes

The Notes for the LRA 3.X.2 Tables, which reference the Thermal Aging & Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) AMP, are changed from either Note A to Note B or Note C to Note D, to reflect the change in the status of the AMP from "AMP is consistent with NUREG-1801 AMP" to "AMP takes some exceptions to NUREG-1801 AMP".

Bolting Integrity (NUREG-1801, XI.M18)

Alternatives Impacting AMP

The following MNGP ASME Section XI Program approved alternatives impact AMP B2.1.4:

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program

Justification for use of Alternatives

·Alternative No. 7 - Use of 2001 Edition for Repair/ Replacement Program: The justification is identical to the ASME Section XI In-Service Inspection, Subsections IWB, IWC, and IWD AMP.

LRA Changes

B2.1.4 Bolting Integrity

The above alternative and the associated justification are added to the "Exceptions to NUREG-1801" subsection of the LRA for AMP B2.1.4 and to the appropriate AMP program element discussions. Further, the statement under the "Detection of Aging Effects" regarding "except as allowed by code cases, relief requests, or interpretations" is removed. Also, the statement under the "Corrective Actions" regarding "per a previously approved ISI Relief Request" is removed.

The reference to the "risk-informed methodology" is removed from the "Monitoring and Trending" subsection of the LRA for AMP B2.1.4.

3.X.2 Table Changes

The Notes for the LRA 3.X.2 Tables, which reference the Bolting Integrity AMP, are changed from either Note A to Note B or Note C to Note D, to reflect the change in the status of the AMP from "AMP is consistent with NUREG-1801 AMP" to "AMP takes some exceptions to NUREG-1801 AMP".

Primary Containment In-Service Inspection Program (NUREG-1801, XI.S1)

Alternatives Impacting AMP

·None

Justification for use of Alternatives

·Not Applicable

LRA Changes

B2.1.26 Primary Containment In-Service Inspection Program

The statement under the "NUREG-1801 Consistency" regarding "Exceptions to ASME Code requirements that have been granted by approved Code Cases or relief requests are not considered to be exceptions to NUREG-1801 criteria." is removed. The statement is not required. ASME Section XI, Subsection IWE alternatives expire prior to the period of extended operation.

The statement under the "Scope of Program" regarding "These are not considered exceptions since the MNGP program has been reviewed by the NRC and is in accordance with 10CFR50.55a with NRC approved relief requests." is removed. The statement is not required. ASME Section XI, Subsection IWE alternatives expire prior to the period of extended operation.

The statement under the "Parameters Monitored or Inspected" regarding "These are not considered exceptions since the MNGP program has been reviewed by the NRC and is in accordance with 10CFR50.55a with NRC approved relief requests." is removed. The statement is not required. ASME Section XI, Subsection IWE alternatives expire

prior to the period of extended operation.

The statement under the "Detection of Aging Effects" regarding "This is not considered an exception since the MNGP program has been reviewed by the NRC and is in accordance with 10CFR50.55a with NRC approved relief requests." is removed. The statement is not required. ASME Section XI, Subsection IWE alternatives expire prior to the period of extended operation.

The statement under the "Monitoring and Trending" regarding "This is not considered an exception since the MNGP program has been reviewed by the NRC and is in accordance with 10CFR50.55a with NRC approved relief requests." is removed. The statement is not required. ASME Section XI, Subsection IWE alternatives expire prior to the period of extended operation.

The statement under the "Corrective Actions" regarding "This is not considered an exception since the MNGP program has been reviewed by the NRC and is in accordance with 10CFR50.55a with NRC approved relief requests." is removed. The statement is not required. ASME Section XI, Subsection IWE alternatives expire prior to the period of extended operation.

The statement under the "Confirmation Process" regarding "This is not considered an exception since the MNGP program has been reviewed by the NRC and is in accordance with 10CFR50.55a with NRC approved relief requests." is removed. The statement is not required. ASME Section XI, Subsection IWE alternatives expire prior to the period of extended operation.

ASME Section XI, Subsection IWF (NUREG-1801, XI.S3)

Alternatives Impacting AMP

The following MNGP ASME Section XI Program approved alternatives impact AMP B2.1.3:

·Code Case N-491-2 - Rules for Examination of Class 1, 2, 3, and MC Component Supports of Light-Water Cooled Power Plants, Section XI, Division 1

Justification for use of Alternatives

·Code Case N-491-2 - Rules for Examination of Class 1, 2, 3, and MC Component Supports of Light-Water Cooled Power Plants, Section XI, Division 1:

MNGP allows for corrective measures to be performed on a component support to return the support to its design condition after acceptance by evaluation or test, without requiring additional examinations. This alternative involves corrective actions of component supports and has no impact on the aging management of the supports.

(Reference: Justification is derived from the "Aging Management Discussion" section of Table 2 of Enclosure 1 of Reference A for the "Code Case N-491-2".)

LRA Changes

B2.1.3 ASME Section XI, Subsection IWF

The above alternative and the associated justification is added to the "Exceptions to NUREG-1801" subsection of the LRA for AMP B2.1.3 and to the appropriate AMP program element discussions.

3.X.2 Table Changes

The Notes for the LRA 3.X.2 Tables, which reference the ASME Section XI, Subsection IWF AMP, are changed from either Note A to Note B or Note C to Note D, to reflect the change in the status of the AMP from "AMP is consistent with NUREG-1801 AMP" to "AMP takes some exceptions to NUREG-1801 AMP".

Audit Question No.: B2.1.33-1

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Wen **MNGP Owner:** Mike Aleksey **Discipline:** Programs

Question:

1. In MNGP LRA Appendix B2.1.33, the applicant briefly described the screening criteria for determining the susceptibility of CASS components to thermal aging. These criteria are based on casting method, molybdenum content, and percent ferrite. Confirm that the criteria used by the applicant are same as given in GALL AMP XI.M13. Also confirm that a supplemental inspection program that is qualified for detecting the critical flaw size with adequate margin will be provided for the CASS components whose function is affected.

2. In GALL AMP XI.M13, void swelling is also identified as an aging mechanism leading to loss of fracture toughness in CASS reactor vessel internals. MNGP LRA Appendix B2.1.33 is silent on this respect. If applicant determines that void swelling is not applicable, please provide the technical basis for such conclusion.

3. Please provide some examples to demonstrate that the aging effects of CASS reactor vessel internals have been effectively managed by this AMP, as stated In the "Operating Experience" section of MNGP LRA Appendix B2.1.33.

Date Received: 6/9/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - B2.1.33-01

Draft Response:

1. The MNGP program corresponding to the GALL Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program is part of the ASME Section XI Inservice Inspection (ISI) Program as augmented with BWRVIP guidance. Program implementation activities (e.g. such as inclusion of enhanced visual examination for affected components) will be completed prior to the period of extended operation to ensure consistency with GALL. All of the vessel internal CASS components within the scope of license renewal will be included in the MNGP program, unless excluded based on GALL screening criteria (e.g. fluence, casting method, molybdenum content, and percent ferrite). These components consist of jet pump assembly castings, the orifice fuel support casting and the guide tube base casting.

2. EPRI TR-107521, Generic License Renewal Technical Issues Summary, EPRI, April 1998, addressed data gathered from Liquid-Metal-Cooled Fast Breeder Reactors (LMFBRS), and how it may possibly be related to PWR components that are in almost direct contact with the fuel. Subsequently EPRI Final Report No. 1000866 (Summary of Generic License Renewal Technical Issues), June 2001 was issued which updated and summarized TR-107521.

A BWR does not have components located in a similar location, and thus, can reasonably be expected to experience less fluence than a PWR. Past studies of void swelling by ANL, ORNL, HEDL and GE have shown that the threshold fluence for void swelling is approximately 1E22 n/cm2, which is well in excess of the fluences experienced by BWR components. Secondly, the EPRI reports note that field experience does not support void swelling being a significant issue. The lowest temperature for which this phenomenon is conjectured to occur is 300°C (572°F), which is higher than the internals that the MNGP will experience. Further, the RPV and Internals ISI program that implements the NRC staff approved BWRVIP program for BWR internals addresses the key aspects of the internals components and provides inspection criteria where appropriate to manage aging. The BWRVIP Program that is implemented at the MNGP is adequate to address aging of the internals.

3. To date all inspections have been in accordance with the guidance of the BWRVIP program. Results of inspections for CASS components are included in Refueling Outage Inspection Reports, the most recent of which was prepared for the 2005 refueling outage. It should be noted that all internals CASS components are exposed to a relatively low operating stress and fluence level. No flaw indications in these components have been identified to date.

MNGP's inspection programs have demonstrated on several occasions that aging effects are effectively managed. The following provides a summary of recent inspection and assessment results that substantiate effective implementation:

NRC Integrated Inspection Report, 50-263/03-04, 4/1/03 through 6/30/03 - ISI program review was conducted with in-process observations and NDE examination reviews during RFO 21. Compliance to ASME code requirements was evaluated. ISI procedures, personnel qualification, and NIS-2 forms were reviewed. ISI-related problems documented in the site CA process were reviewed. No findings of significance were identified.

ANSI N626.1/QAI-1 Audit - Six Month Audit of the Authorized Nuclear Inservice Inspector (ANII) by the Authorized Nuclear Inspection Agency. ANI audit conclusions:· No items were noted that required resolution, three items from the previous audit will be resolved when the Containment Inspection Plan is revised (Audit 2003-1), all

deficiencies identified were corrected and closed prior to completion of the audit (Audit 2003-2), No deficiencies were identified (Audit 2004-1), one corrective action was initiated (Audit 2004-2).

NMC Nuclear Oversight Observation Conducted during RFO 21 (2003) - Two Year Audit of the Inservice Inspection Program by the NMC Nuclear Oversight Section, evaluated the ISI Program as acceptable in that:· Provisions are made for flaw evaluation & disposition, ISI personnel are qualified, the CA process is used for negative indications, NDE procedures are created & used, program & activities comply with 10CFR50.55a, risk-informed ISI satisfies the guidelines of EPRI TR-112657.

Snapshot Self-Assessment 4/14/03 through 4/16/03 - This self-assessment reports an effectiveness review of administrative & implementation requirements of portions of the ISI Program including the ISI, R/R and IWE elements. The program was compared to NRC Inspection Procedures 71111.08, 73051,73052, 73053, & 73055. No significant discrepancies were identified. Discrepancies identified were administrative in nature & related to organization changes. These discrepancies were entered in the site's CA process.

Self Assessment of ISI/NDE, 2003 RFO - This self-assessment is a post review of ISI activities conducted during RFO 21. It lists areas for improvement, none of which reflect on the ability of the ISI program to manage aging effects.

Inservice Inspection Summary Report, August 8, 2003 - The inspection summary of this report states:· All of the examinations performed during Cycle 21 met the Code examination requirements; for Class 1, 2, 3, non-code commitment, augmented, and site requested examinations all listed anomalies were either corrected, or an engineering evaluation was performed to accept "as-is" conditions; results of the ISI activities indicate the integrity of the plant systems has been maintained.

Final Response: 6/15/05 Status, Question subpart 1: OPEN, Question Subpart 2: Sufficient per NRC, Question Subpart 3: Open

Audit Question No.: B2.1.7-01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Wen **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question: 1. In MNGP LRA Appendix B.2.1.7, the applicant states that in 1977 the CRDRL nozzle safe end was removed and the CRDRL nozzle was capped. The applicant also states that in 1986 the CRDRL nozzle was modified again by re-cladding the weld prep area with corrosion resistant cladding and by installing a new stainless steel nozzle cap. Please explain why applicant made such extensive modifications? Through what mechanisms the applicant realized that such modifications were necessary?

Date Received: 6/7/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: SIL 200, "Control Rod Drive Return Line Modification", October 29, 1976, was issued to discuss cracking of the CRD return lines discovered in several BWR plants. Evidence of both intergranular stress corrosion cracking and fatigue cracking was found in the other BWR plants. The factors contributing to these types of crack phenomena include thermal gradients and thermal cycling. This SIL recommended the following:

1) Reroute the CRD hydraulic return line to the reactor water cleanup system.
2) Remove the thermal sleeve from the reactor CRD return nozzle and cap the RPV nozzle with material immune to stress corrosion cracking.
3) Perform the appropriate CRD system modifications to provide satisfactory CRD system performance after the CRD return line is re-routed.

In 1977, the CRD return line was modified due to its susceptibility to IGSCC. As a result, the CRD hydraulic return nozzle safe end was removed and the CRD nozzle was capped using a 4" diameter pipe cap.

In 1986, the CRD return nozzle, was again modified. The purpose of this modification was to remove that portion of the existing weld butter layer susceptible to IGSCC and re-clad the weld prep area with corrosion resistant cladding and install a new nozzle cap. This second modification was a proactive action. No cracking of the weld between the nozzle and the end cap had been identified.

Generic Letter 80-95 was issued to forward the revised and final edition of NUREG-0619 "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking" to licensees. Generic letter 80-95 required licensees to implement the requirements contained in NUREG-0619. In response to GL 80-95, MNGP committed (License Commitment No. M81027A) to implement the requirements for the CRD return line nozzle specified in Section 8 of NUREG-0619 with the exception of Section 8.1.4.c'.

JPP 6/16/05

Final Response: SIL 200, "Control Rod Drive Return Line Modification", October 29, 1976, was issued to discuss cracking of the CRD return lines discovered in several BWR plants. Evidence of both intergranular stress corrosion cracking and fatigue cracking was found in the other BWR plants. The factors contributing to these types of crack phenomena include thermal gradients and thermal cycling. This SIL recommended the following:

1) Reroute the CRD hydraulic return line to the reactor water cleanup system.
2) Remove the thermal sleeve from the reactor CRD return nozzle and cap the RPV nozzle with material immune to stress corrosion cracking.
3) Perform the appropriate CRD system modifications to provide satisfactory CRD system performance after the CRD return line is re-routed.

In 1977, the CRD return line was modified due to its susceptibility to IGSCC. As a result, the CRD hydraulic return nozzle safe end was removed and the CRD nozzle was capped using a 4" diameter pipe cap.

In 1986, the CRD return nozzle, was again modified. The purpose of this modification was to remove that portion of the existing weld butter layer susceptible to IGSCC and re-clad the weld prep area with corrosion resistant cladding and install a new nozzle cap. This second modification was a proactive action. No cracking of the weld between the nozzle and the end cap had been identified.

Generic Letter 80-95 was issued to forward the revised and final edition of NUREG-0619 "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking" to

licensees. Generic letter 80-95 required licensees to implement the requirements contained in NUREG-0619. In response to GL 80-95, MNGP committed to implement the requirements for the CRD return line nozzle specified in Section 8 of NUREG-0619 with the exception of Section 8.1.4.c.

Audit Question No.: B2.1.7-02

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Wen **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question: 2. In MNGP LRA Appendix B.2.1.7, the applicant states that the MNGP programs do not provide for the augmented inspections specified in NUREG-0619 for the CRDRL nozzles, because the nozzles have been capped. However, Section 8.2 of NUREG-0619 requires augmented inspections depending on how the capped line was rerouted. Explain how the CRDRL was rerouted, and provide the applicable augmented inspection for these pressure boundary nozzles. (LRA Table 2.3.1-2 indicates that the intended function for these nozzle is pressure boundary.)

Date Received: 6/7/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The CRDRL nozzle has been cut and capped. The line was rerouted to the Reactor Water Clean-up System with the rerouted line flow valve closed. MNGP does not perform any NUREG-0619 augmented inspections on the nozzle or cap, but does follow the guidance in Section 8.2 for other inspections and maintenance activities related to the CRD system.

The following is a summary of MNGP activities related to Section 8.2 of NUREG-0619:

-Section 8.2(3) The final PT inspection of the CRDRL nozzle showed no indications. A system flow and performance test was conducted with satisfactory results.
-Section 8.2(3a) The welded connection joining the rerouted CRDRL to the Reactor Water Clean-up System is inspected every refueling outage. This inspection is performed with UT and includes base metal to a distance of one-pipe-wall thickness, or 0.5 inches, whichever is greater, on both sides of the weld.
-Section 8.2(3b) The remainder of the CRDRL does not meet the definition of Class 1, 2, or 3 pipe and, therefore, NUREG-0313 does not require augmented inspections.
-Section 8.2(3c) Since carbon steel piping was retained in the exhaust header, procedures were developed to perform the following activities:
1. Inspect and replace the hydraulic control unit (HCU) filters every refueling outage
2. Flush the exhaust water header every refueling outage

The activities described above relating to NUREG-0619 Sections 8.2(3a) and 8.2(3c) are existing NRC commitments and will continue through the period of extended operation.

JPP 6/16/05

Final Response: The CRDRL nozzle has been cut and capped. The line was rerouted to the Reactor Water Clean-up System with the rerouted line flow valve closed. MNGP does not perform any NUREG-0619 augmented inspections on the nozzle or cap, but does follow the guidance in Section 8.2 for other inspections and maintenance activities related to the CRD system.

The following is a summary of MNGP activities related to Section 8.2 of NUREG-0619:

-Section 8.2(3) The final PT inspection of the CRDRL nozzle showed no indications. A system flow and performance test was conducted with satisfactory results.
-Section 8.2(3a) The welded connection joining the rerouted CRDRL to the Reactor Water Clean-up System is inspected every refueling outage. This inspection is performed with UT and includes base metal to a distance of one-pipe-wall thickness, or 0.5 inches, whichever is greater, on both sides of the weld.
-Section 8.2(3b) The remainder of the CRDRL does not meet the definition of Class 1, 2, or 3 pipe and, therefore, NUREG-0313 does not require augmented inspections.
-Section 8.2(3c) Since carbon steel piping was retained in the exhaust header, procedures were developed to perform the following activities:
1. Inspect and replace the hydraulic control unit (HCU) filters every refueling outage
2. Flush the exhaust water header every refueling outage

The activities described above relating to NUREG-0619 Sections 8.2(3a) and 8.2(3c) are existing NRC commitments and will continue through the period of extended operation.

Audit Question No.: B2.1.7-03

Source: **AMP Audit** **Status:** **Sufficient per NRC** **Author:** **Wen** **MNGP Owner:** **Bill O'Brien** **Discipline:** **Mechanical**

Question: 3. Describe the experience of BWR CRDRL Nozzle Program at MNGP to detect CRDRL nozzle aging degradation and the associated corrective actions taken by MNGP. Please include the discussion on the most recent CRDRL nozzle inspection findings.

Date Received: 6/7/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Since the last modification to the capped nozzle in 1986, the following inspections have been conducted:

1. In April of 1996, a liquid penetrant examination (PT) was performed on the nozzle to end cap weld. No reportable indications were found.
2. In March of 2005, a visual examination (VT-1) was performed on the nozzle to end cap weld. No reportable indications were found.

JPP 6/16/05

Final Response: Since the last modification to the capped nozzle in 1986, the following inspections have been conducted:

1. In April of 1996, a liquid penetrant examination (PT) was performed on the nozzle to end cap weld. No reportable indications were found.
2. In March of 2005, a visual examination (VT-1) was performed on the nozzle to end cap weld. No reportable indications were found.

Audit Question No.: B2.1.7-04

Source: **AMP Audit** **Status:** **Sufficient per NRC** **Author:** **Wen** **MNGP Owner:** **Bill O'Brien** **Discipline:** **Mechanical**

Question: 4. Please confirm that CRDRL nozzle remains within the ISI program plan. Is it listed in the ISI program plan 10-years inspection interval?

Date Received: 6/7/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: The CRDRL nozzle is included in the MNGP ISI Program, IWB-2500-1, Examination Category B-D. The ISI Program has two areas scheduled for inspection: the inner radius and the nozzle to vessel weld.

JPP 6/9/05

Final Response: The CRDRL nozzle is included in the MNGP ISI Program, IWB-2500-1, Examination Category B-D. The ISI Program has two areas scheduled for inspection: the inner radius and the nozzle to vessel weld.

Audit Question No.: B2.1.8 -01

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Wen **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question: 1. The staff has approved BWROG topical report GE-NE 523-A71-0594, Revision1, "Alternate BWR Feedwater Nozzle Inspection Requirements," to be used as an acceptable alternative to the inspection guidelines in NUREG-0619. However, the applicant indicates that MNGP currently has not implemented the recommendations described in this topical report. Please confirm that those recommendations presented in the topical report will be implemented at MNGP.

Date Received: 6/7/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: Per MNGP License Renewal Application, Section B2.1.8, "BWR Feedwater Nozzle", the following enhancements are discussed.

Enhancements
The following enhancement(s) are required to satisfy the NUREG-1801 aging management program recommendations. Details of the enhancements are included in the appropriate element descriptions below. These enhancements are scheduled for implementation prior to the period of extended operation and are listed as commitments 18, 19, and 20, respectively, in Appendix A of the MNGP License Renewal Application.

-Parameters Monitored/Inspected
The BWR Feedwater Nozzle Program will be enhanced so that the parameters monitored and inspected are consistent with the recommendations of GENE-523-A71-0594-A, Revision 1.

- Detection of Aging Effects
The BWR Feedwater Nozzle Program will be enhanced so the regions being inspected, examination techniques, personnel qualifications, and inspection schedule are consistent with the recommendations of GE NE-523-A71-0594-A,
Revision 1.

- Monitoring and Trending
The BWR Feedwater Nozzle Program will be enhanced so that inspections will be scheduled per recommendations of
GENE-523-A71-0594-A, Revision 1.

JPP 6/9/05

Final Response: Per MNGP License Renewal Application, Section B2.1.8, "BWR Feedwater Nozzle", the following enhancements are discussed.

Enhancements
The following enhancement(s) are required to satisfy the NUREG-1801 aging management program recommendations. Details of the enhancements are included in the appropriate element descriptions below. These enhancements are scheduled for implementation prior to the period of extended operation and are listed as commitments 18, 19, and 20, respectively, in Appendix A of the MNGP License Renewal Application.

-Parameters Monitored/Inspected
The BWR Feedwater Nozzle Program will be enhanced so that the parameters monitored and inspected are consistent with the recommendations of GENE-523-A71-0594-A, Revision 1.

- Detection of Aging Effects
The BWR Feedwater Nozzle Program will be enhanced so the regions being inspected, examination techniques, personnel qualifications, and inspection schedule are consistent with the recommendations of GE NE-523-A71-0594-A,
Revision 1.

- Monitoring and Trending
The BWR Feedwater Nozzle Program will be enhanced so that inspections will be scheduled per recommendations of GENE-523-A71-0594-A, Revision 1.

Audit Question No.: B2.1.8-02

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Wen **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question: 2. Please discuss MNGP feedwater nozzle cracking experience and corrective actions taken.

Date Received: 6/7/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: LER/AO 75-20, "Discovery of Feedwater Nozzle Surface Cracks", October 22, 1975. MNGP reported an event in which indications of cracking on inner blend radii of four reactor vessel feedwater nozzles were revealed by liquid penetrant examinations. The cause of this occurrence was determined to be high cycle thermal fatigue at the nozzle corner radii caused by intermittent flow of cooler feedwater over the feedwater nozzle. All indications of flaws were removed by grinding. MNGP committed (License Commitment No. M75020A) to install improved thermal sleeves as recommended by component supplier (GE) to limit leakage of feedwater past thermal sleeve which caused thermal cycling at blend radii. Replacement feedwater spargers were installed which have an improved thermal sleeve. The new thermal sleeve design uses an interference fit which limits bypass flow to an acceptable level. MNGP recommended that periodic inspection of the feedwater nozzles be conducted to ensure that all flaws will be found substantially before they reach the ASME Code allowable size. New feedwater nozzle safe ends featuring a tuning fork design with a welded in thermal sleeve were installed in 1981. This modification was performed to provide a significant reduction in thermal cycling of the feedwater nozzle area by removing the bypass leakage path from the safe end/nozzle area. No evidence of thermal-induced cracking has been found since removal of the cladding in 1977.

In 1989, MNGP made four long-term inspection commitments based on NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Cracking." The four commitments were as follows:

1. Review on-line feedwater nozzle thermal sleeve leak detection system data on a monthly basis.
2. Perform external UT examinations on two of the four feedwater nozzles each refueling outage.
3. Perform visual inspections of the spargers and the nozzle blend radius area of all four feedwater nozzles each refueling outage.
4. Perform PT examinations of nozzles at the next appropriate opportunity in the event that: a.) UT examinations indicate a flaw or b.) Excessive leakage (greater than 0.3 gpm) is identified by the on-line leakage monitoring systems.

The NRC Safety Evaluation Report (SER) stated that NSP will continue inspections for "9 Inspection Interval-Refueling Cycles or 135 Startup/Shutdown Cycles" as stated in NUREG-0619. The inspection interval began with the installation of welded thermal sleeves during the 1981 refueling outage. With the completion of inspections during the 1998 refueling outage, Monticello completed the required 9 Inspection Interval-Refueling Cycles with no observed degradation of the feedwater nozzles. Commitments 1, 2, and 4 were fully implemented as required.

Commitment 3 specified a visual inspection of the spargers and nozzle blend radius areas on all four feedwater nozzles each outage. All four nozzles were visually inspected in 1984, 1986, 1987, 1989, 1991 and 1996 with no cracking detected; however, during the 1993, 1994, and 1998 outages, only two of the nozzles were visually inspected. This deviation from the commitment occurred due to a 1991 augmented in-service inspection (ISI) database programming error. These missed surveillances were evaluated under NSP's corrective action program. As a result, a new commitment was made to visually inspect reactor pressure vessel feedwater nozzles N-4A and N-4D from the vessel ID during the next refueling outage scheduled for January of 2000. This commitment was completed as written with acceptable results.

Due to the excellent performance history of the MNGP feedwater nozzles with the new thermal sleeves and the improved UT scan detection technique for identifying smaller flaws, continued monitoring in accordance with NUREG-0619 was no longer warranted. MNGP's ongoing ISI UT testing program based on ASME Section XI testing frequencies provides an effective and reliable means for early detection of thermal fatigue crack growth within the feedwater nozzles. Inspections are currently performed in accordance with the ISI Program (inspection of each nozzle at least once within the 10-year inspection interval).

JPP 6/15/05

Final Response: LER/AO 75-20, "Discovery of Feedwater Nozzle Surface Cracks", October 22, 1975. MNGP reported an event in which indications of cracking on inner blend radii of four reactor vessel feedwater nozzles were revealed by liquid penetrant examinations. The cause of this occurrence was determined to be high cycle thermal fatigue at the nozzle

corner radii caused by intermittent flow of cooler feedwater over the feedwater nozzle. All indications of flaws were removed by grinding. MNGP committed (License Commitment No. M75020A) to install improved thermal sleeves as recommended by component supplier (GE) to limit leakage of feedwater past thermal sleeve which caused thermal cycling at blend radii. Replacement feedwater spargers were installed which have an improved thermal sleeve. The new thermal sleeve design uses an interference fit which limits bypass flow to an acceptable level. MNGP recommended that periodic inspection of the feedwater nozzles be conducted to ensure that all flaws will be found substantially before they reach the ASME Code allowable size. New feedwater nozzle safe ends featuring a tuning fork design with a welded in thermal sleeve were installed in 1981. This modification was performed to provide a significant reduction in thermal cycling of the feedwater nozzle area by removing the bypass leakage path from the safe end/nozzle area. No evidence of thermal-induced cracking has been found since removal of the cladding in 1977.

In 1989, MNGP made four long-term inspection commitments based on NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Cracking." The four commitments were as follows:

1. Review on-line feedwater nozzle thermal sleeve leak detection system data on a monthly basis.
2. Perform external UT examinations on two of the four feedwater nozzles each refueling outage.
3. Perform visual inspections of the spargers and the nozzle blend radius area of all four feedwater nozzles each refueling outage.
4. Perform PT examinations of nozzles at the next appropriate opportunity in the event that: a.) UT examinations indicate a flaw or b.) Excessive leakage (greater than 0.3 gpm) is identified by the on-line leakage monitoring systems.

The NRC Safety Evaluation Report (SER) stated that NSP will continue inspections for "9 Inspection Interval-Refueling Cycles or 135 Startup/Shutdown Cycles" as stated in NUREG-0619. The inspection interval began with the installation of welded thermal sleeves during the 1981 refueling outage. With the completion of inspections during the 1998 refueling outage, Monticello completed the required 9 Inspection Interval-Refueling Cycles with no observed degradation of the feedwater nozzles. Commitments 1, 2, and 4 were fully implemented as required.

Commitment 3 specified a visual inspection of the spargers and nozzle blend radius areas on all four feedwater nozzles each outage. All four nozzles were visually inspected in 1984, 1986, 1987, 1989, 1991 and 1996 with no cracking detected; however, during the 1993, 1994, and 1998 outages, only two of the nozzles were visually inspected. This deviation from the commitment occurred due to a 1991 augmented in-service inspection (ISI) database programming error. These missed surveillances were evaluated under NSP's corrective action program. As a result, a new commitment was made to visually inspect reactor pressure vessel feedwater nozzles N-4A and N-4D from the vessel ID during the next refueling outage scheduled for January of 2000. This commitment was completed as written with acceptable results.

Due to the excellent performance history of the MNGP feedwater nozzles with the new thermal sleeves and the improved UT scan detection technique for identifying smaller flaws, continued monitoring in accordance with NUREG-0619 was no longer warranted. MNGP's ongoing ISI UT testing program based on ASME Section XI testing frequencies provides an effective and reliable means for early detection of thermal fatigue crack growth within the feedwater nozzles. Inspections are currently performed in accordance with the ISI Program (inspection of each nozzle at least once within the 10-year inspection interval).

Audit Question No.: B2.1.8-03

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Wen **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question: 3. Please discuss the inspection findings since the completion of feedwater nozzle modifications in 1981.

Date Received: 6/7/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: In 1989, MNGP made four long-term inspection commitments based on NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Cracking." The four commitments were as follows:

1. Review on-line feedwater nozzle thermal sleeve leak detection system data on a monthly basis.
2. Perform external UT examinations on two of the four feedwater nozzles each refueling outage.
3. Perform visual inspections of the spargers and the nozzle blend radius area of all four feedwater nozzles each refueling outage.
4. Perform PT examinations of nozzles at the next appropriate opportunity in the event that: a.) UT examinations indicate a flaw or b.) Excessive leakage (greater than 0.3 gpm) is identified by the on-line leakage monitoring systems.

The NRC Safety Evaluation Report (SER) stated that NSP will continue inspections for "9 Inspection Interval-Refueling Cycles or 135 Startup/Shutdown Cycles" as stated in NUREG-0619. The inspection interval began with the installation of welded thermal sleeves during the 1981 refueling outage. With the completion of inspections during the 1998 refueling outage, Monticello completed the required 9 Inspection Interval-Refueling Cycles with no observed degradation of the feedwater nozzles. Commitments 1, 2, and 4 were fully implemented as required.

Commitment 3 specified a visual inspection of the spargers and nozzle blend radius areas on all four feedwater nozzles each outage. All four nozzles were visually inspected in 1984, 1986, 1987, 1989, 1991 and 1996 with no cracking detected; however, during the 1993, 1994, and 1998 outages, only two of the nozzles were visually inspected. This deviation from the commitment occurred due to a 1991 augmented in-service inspection (ISI) database programming error. These missed surveillances were evaluated under NSP's corrective action program. As a result, a new commitment was made to visually inspect reactor pressure vessel feedwater nozzles N-4A and N-4D from the vessel ID during the next refueling outage scheduled for January of 2000. This commitment was completed as written with acceptable results (no indications).

Due to the excellent performance history of the MNGP feedwater nozzles with the new thermal sleeves and the improved UT scan detection technique for identifying smaller flaws, continued monitoring in accordance with NUREG-0619 was no longer warranted. MNGP's ongoing ISI UT testing program based on ASME Section XI testing frequencies provides an effective and reliable means for early detection of thermal fatigue crack growth within the feedwater nozzles. Inspections are currently performed in accordance with the ISI Program (inspection of each nozzle at least once within the 10-year inspection interval).

JPP 6/15/05

Final Response: In 1989, MNGP made four long-term inspection commitments based on NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Cracking." The four commitments were as follows:

1. Review on-line feedwater nozzle thermal sleeve leak detection system data on a monthly basis.
2. Perform external UT examinations on two of the four feedwater nozzles each refueling outage.
3. Perform visual inspections of the spargers and the nozzle blend radius area of all four feedwater nozzles each refueling outage.
4. Perform PT examinations of nozzles at the next appropriate opportunity in the event that: a.) UT examinations indicate a flaw or b.) Excessive leakage (greater than 0.3 gpm) is identified by the on-line leakage monitoring systems.

The NRC Safety Evaluation Report (SER) stated that NSP will continue inspections for "9 Inspection Interval-Refueling Cycles or 135 Startup/Shutdown Cycles" as stated in NUREG-0619. The inspection interval began with the installation of welded thermal sleeves during the 1981 refueling outage. With the completion of inspections during the 1998 refueling outage, Monticello completed the required 9 Inspection Interval-Refueling Cycles with no observed degradation of the

feedwater nozzles. Commitments 1, 2, and 4 were fully implemented as required.

Commitment 3 specified a visual inspection of the spargers and nozzle blend radius areas on all four feedwater nozzles each outage. All four nozzles were visually inspected in 1984, 1986, 1987, 1989, 1991 and 1996 with no cracking detected; however, during the 1993, 1994, and 1998 outages, only two of the nozzles were visually inspected. This deviation from the commitment occurred due to a 1991 augmented in-service inspection (ISI) database programming error. These missed surveillances were evaluated under NSP's corrective action program. As a result, a new commitment was made to visually inspect reactor pressure vessel feedwater nozzles N-4A and N-4D from the vessel ID during the next refueling outage scheduled for January of 2000. This commitment was completed as written with acceptable results (no indications).

Due to the excellent performance history of the MNGP feedwater nozzles with the new thermal sleeves and the improved UT scan detection technique for identifying smaller flaws, continued monitoring in accordance with NUREG-0619 was no longer warranted. MNGP's ongoing ISI UT testing program based on ASME Section XI testing frequencies provides an effective and reliable means for early detection of thermal fatigue crack growth within the feedwater nozzles. Inspections are currently performed in accordance with the ISI Program (inspection of each nozzle at least once within the 10-year inspection interval).

Audit Question No.: B2.1.8-04

Source: AMP Audit **Status:** Sufficient per NRC **Author:** Wen **MNGP Owner:** Bill O'Brien **Discipline:** Mechanical

Question: 4. As described in NUREG-0619, Rev-1, a leak monitoring system could provide direct assessment of conditions of thermal sleeve bypass due to degraded thermal sleeve seals or cracks in the welds. Clarify if this system has been implemented in MNGP, if so, please describe its operating experience.

Date Received: 6/7/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - Appendix B

Draft Response: In 1989, MNGP made four long-term inspection commitments based on NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Cracking." The four commitments were as follows:

1. Review on-line feedwater nozzle thermal sleeve leak detection system data on a monthly basis.
2. Perform external UT examinations on two of the four feedwater nozzles each refueling outage.
3. Perform visual inspections of the spargers and the nozzle blend radius area of all four feedwater nozzles each refueling outage.
4. Perform PT examinations of nozzles at the next appropriate opportunity in the event that: a.) UT examinations indicate a flaw or b.) Excessive leakage (greater than 0.3 gpm) is identified by the on-line leakage monitoring systems.

The NRC Safety Evaluation Report (SER) stated that NSP will continue inspections for "9 Inspection Interval-Refueling Cycles or 135 Startup/Shutdown Cycles" as stated in NUREG-0619. The inspection interval began with the installation of welded thermal sleeves during the 1981 refueling outage. With the completion of inspections during the 1998 refueling outage, Monticello completed the required 9 Inspection Interval-Refueling Cycles with no observed degradation of the feedwater nozzles. Commitments 1, 2, and 4 were fully implemented as required.

With the implementation of the welded thermal sleeve modification and subsequent inspections through the 1998 refueling outage as stated above, the commitment to monitor leakage monthly via the feedwater nozzle leakage monitoring system was completed. Therefore, the feedwater nozzle leakage monitoring system was no longer needed and was abandoned. However, inspections of the feedwater nozzles continue in accordance with the ASME Section XI ISI Program.

JPP 6/15/05

Final Response: In 1989, MNGP made four long-term inspection commitments based on NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Cracking." The four commitments were as follows:

1. Review on-line feedwater nozzle thermal sleeve leak detection system data on a monthly basis.
2. Perform external UT examinations on two of the four feedwater nozzles each refueling outage.
3. Perform visual inspections of the spargers and the nozzle blend radius area of all four feedwater nozzles each refueling outage.
4. Perform PT examinations of nozzles at the next appropriate opportunity in the event that: a.) UT examinations indicate a flaw or b.) Excessive leakage (greater than 0.3 gpm) is identified by the on-line leakage monitoring systems.

The NRC Safety Evaluation Report (SER) stated that NSP will continue inspections for "9 Inspection Interval-Refueling Cycles or 135 Startup/Shutdown Cycles" as stated in NUREG-0619. The inspection interval began with the installation of welded thermal sleeves during the 1981 refueling outage. With the completion of inspections during the 1998 refueling outage, Monticello completed the required 9 Inspection Interval-Refueling Cycles with no observed degradation of the feedwater nozzles. Commitments 1, 2, and 4 were fully implemented as required.

With the implementation of the welded thermal sleeve modification and subsequent inspections through the 1998 refueling outage as stated above, the commitment to monitor leakage monthly via the feedwater nozzle leakage monitoring system was completed. Therefore, the feedwater nozzle leakage monitoring system was no longer needed and was abandoned. However, inspections of the feedwater nozzles continue in accordance with the ASME Section XI ISI Program.

Audit Question No.: B2.1.8-05

Source: **AMP Audit** **Status:** **Sufficient per NRC** **Author:** **Wen** **MNGP Owner:** **Jim Rootes** **Discipline:** **Programs**

Question: Question on B2.1.8 BWR FW Nozzle Program (Wen)

1. In MNGP LRA, the applicant states that the BWR FW Nozzle Program will be enhanced to be consistent with the recommendations of GALL AMP XI.M5. Please clarify in details how MNGP plans to upgrade its current program to meet the GALL recommendations. Please provide these details in the content of "Parameters Monitoring/Inspected," "Detection of Aging Effects," and "Monitoring and Training" program elements.

Date Received: 7/20/2005 Potential Submittal on ☐ Potential LRA Update Required ☐ Assoc LRA Section - B2.1.8

Draft Response: Parameters Monitored/Inspected

The requirements specified in ASME Section XI Table IWB-2500-1, Examination Category B-D, for full penetration welded nozzles in vessels have been incorporated into the MNGP BWR Feedwater Nozzle Program. In addition, all indications identified are dispositioned in accordance with ASME Section XI with Appendix VIII, which is consistent with the recommendations of GE NE-523-A71-0594-A, Revision 1, Alternate BWR Feedwater Nozzle Inspection Requirements.

The reference to GE NE-523-A71-0594-A, Revision 1 in this NUREG-1801, XI.M05 element (Parameters Monitored/Inspected) points to elements 4 (Detection of Aging Effects) and 5 (Monitoring and Trending) below. There are now specific GE NE-523-A71-0594-A, Revision 1, details related to this element.

Detection of Aging Effects

The requirements of ASME Section XI, Examination Category B-D, with Appendix VIII have been incorporated into the MNGP BWR Feedwater Nozzle Program. The regions being inspected, examination techniques, personnel qualifications, and inspection schedule will be consistent with the recommendations of GE NE-523-A71-0594-A, Revision 1, Section 4.0. The BWR feedwater nozzles are being periodically examined using the ultrasonic (UT) volumetric nondestructive examination method.

Monitoring and Trending

The requirements of ASME Section XI with Appendix VIII, including the schedule requirements of IWB-2400 have been incorporated into the MNGP BWR Feedwater Nozzle Program, which will be enhanced to be consistent with the recommendations of GE NE-523-A71-0594-A, Revision 1, Section 6.2 & 6.3. If defects are detected, the scope of examinations is expanded per the requirements of IWB-2430.

Final Response: Parameters Monitored/Inspected

The requirements specified in ASME Section XI Table IWB-2500-1, Examination Category B-D, for full penetration welded nozzles in vessels have been incorporated into the MNGP BWR Feedwater Nozzle Program. In addition, all indications identified are dispositioned in accordance with ASME Section XI with Appendix VIII, which is consistent with the recommendations of GE NE-523-A71-0594-A, Revision 1, Alternate BWR Feedwater Nozzle Inspection Requirements.

The reference to GE NE-523-A71-0594-A, Revision 1 in this NUREG-1801, XI.M05 element (Parameters Monitored/Inspected) points to elements 4 (Detection of Aging Effects) and 5 (Monitoring and Trending) below. There are now specific GE NE-523-A71-0594-A, Revision 1, details related to this element.

Detection of Aging Effects

The requirements of ASME Section XI, Examination Category B-D, with Appendix VIII have been incorporated into the MNGP BWR Feedwater Nozzle Program. The regions being inspected, examination techniques, personnel qualifications, and inspection schedule will be consistent with the recommendations of GE NE-523-A71-0594-A, Revision 1, Section 4.0. The BWR feedwater nozzles are being periodically examined using the ultrasonic (UT) volumetric nondestructive examination method.

Monitoring and Trending

The requirements of ASME Section XI with Appendix VIII, including the schedule requirements of IWB-2400 have been incorporated into the MNGP BWR Feedwater Nozzle Program, which will be enhanced to be consistent with the recommendations of GE NE-523-A71-0594-A, Revision 1, Section 6.2 & 6.3. If defects are detected, the scope of examinations is expanded per the requirements of IWB-2430.