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INDIANA
MICHIGAN
POWER

October 18, 2004

AEP:NRC:4034-17
10 CFR 54

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Mail Stop O-P1-17
Washington, DC 20555-0001

SUBJECT: Donald C. Cook Nuclear Plant, Units 1 and 2
Docket Nos. 50-315 and 50-316
License Renewal Application – Response to Requests for Additional Information
(TAC Nos. MC1202 and MC1203)

Dear Sir or Madam:

By letter dated October 31, 2003, Indiana Michigan Power Company (I&M) submitted an application to renew the operating licenses for Donald C. Cook Nuclear Plant, Units 1 and 2 (Reference 1).

During the conduct of its review, the Nuclear Regulatory Commission (NRC) Staff has identified areas where additional information is needed to complete its review of the license renewal application (LRA), and issued requests for additional information (RAIs) to obtain the needed information. In some cases, the NRC Staff determined that the information provided in I&M's response to the RAIs did not entirely satisfy the NRC Staff's information needs, and additional clarification was requested via telephone conference calls or meetings. This letter provides I&M's response to three new requests (RAIs 4.7.5-1, B.1.26-2, and B.1.41-2) and supplements I&M's original responses to 26 other RAIs. The RAIs pertain to the following LRA topics:

- Reactor Vessel, Internals, and Reactor Coolant System – Aging Management Review and Programs, and Time-Limited Aging Analyses
- Auxiliary Systems – Aging Management Review and Programs
- Bolting and Torquing – Aging Management Review and Programs
- Electrical Systems – Scoping and Aging Management Review
- Other Time-Limited Aging Analysis Issues
- Other Aging Management Program Issues

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The enclosure to this letter provides an affirmation pertaining to the statements made in this letter. Attachment 1 to this letter provides I&M's responses to the NRC Staff's RAIs and supplemental clarifications to RAIs. Attachment 2 provides a list of regulatory commitments made in this submittal.

Should you have any questions, please contact Mr. Richard J. Grumbir, Project Manager, License Renewal, at (269) 697-5141.

Sincerely,

J. N. Jensen
Site Vice President

NH/rdw

Enclosure: Affirmation

Attachments:
1. Response to Requests for Additional Information for the Donald C. Cook Nuclear Plant License Renewal Application
2. List of Regulatory Commitments

References:

1. Letter from M. K. Nazar, I&M, to NRC Document Control Desk, "Donald C. Cook Nuclear Plant Units 1 and 2, Application for Renewed Operating Licenses," AEP:NRC:3034, dated October 31, 2003 [Accession No. ML033070177].

c: J. L. Caldwell – NRC Region III
K. D. Curry – AEP Ft. Wayne, w/o attachments
J. T. King – MPSC, w/o attachments
C. F. Lyon – NRC Washington DC
MDEQ – WHMD/HWRPS, w/o attachments
NRC Resident Inspector
J. G. Rowley – NRC Washington DC

bc: T. P. Beilman
D. P. Fadel
M. J. Finissi
R. J. Grumbir
N. Haggerty
J. N. Jensen
M. K. Nazar
J. E. Newmiller
D. J. Poupard
M. K. Scarpello, w/o attachments
D. D. Sorrell
P. E. Troy, w/o attachments
T. K. Woods, w/o attachments
J. A. Zwolinski

Enclosure to AEP:NRC:4034-17

AFFIRMATION

I, Joseph N. Jensen, being duly sworn, state that I am Site Vice President of Indiana Michigan Power Company (I&M), that I am authorized to sign and file this request with the Nuclear Regulatory Commission on behalf of I&M, and that the statements made and the matters set forth herein pertaining to I&M are true and correct to the best of my knowledge, information, and belief.

Indiana Michigan Power Company

Joseph N. Jensen
Site Vice President

SWORN TO AND SUBSCRIBED BEFORE ME

THIS 18th DAY OF October, 2004

Notary Public

My Commission Expires 6/10/2007

Response to Requests for Additional Information for the Donald C. Cook Nuclear Plant License Renewal Application

By letter dated October 31, 2003, Indiana Michigan Power Company (I&M) submitted an application to renew the operating licenses for Donald C. Cook Nuclear Plant (CNP), Units 1 and 2 (Reference 1). During the conduct of its review, the Nuclear Regulatory Commission (NRC) Staff has identified areas where additional information is needed to complete its review of the license renewal application (LRA), and issued requests for additional information (RAIs) to obtain the needed information. In some cases, the NRC Staff determined that the information provided in I&M's response to the RAIs did not entirely satisfy the NRC Staff's information needs, and additional clarification was requested via telephone conference calls or meetings.

This attachment provides I&M's response to three new requests (RAIs 4.7.5-1, B.1.26-2, and B.1.41-2) and supplements I&M's original responses to 26 other RAIs. To facilitate the NRC Staff's review, the RAI responses and supplemental RAI responses pertain to the following LRA topics:

- Reactor Vessel, Internals, and Reactor Coolant System – Aging Management Review and Programs, and Time-Limited Aging Analyses
- Auxiliary Systems – Aging Management Review and Programs
- Bolting and Torquing – Aging Management Review and Programs
- Electrical Systems – Scoping and Aging Management Review
- Other Time-Limited Aging Analysis Issues
- Other Aging Management Program Issues

References

1. Letter from M. K. Nazar, I&M, to NRC Document Control Desk, "Donald C. Cook Nuclear Plant Units 1 and 2, Application for Renewed Operating Licenses," AEP:NRC:3034, dated October 31, 2003 [Accession No. ML033070177].

Reactor Vessel, Internals and Reactor Coolant System – Aging Management Review and Programs, and Time-Limited Aging Analyses

RAI 3.1-8:

For flaws in the RPV [reactor pressure vessel] and control rod drive mechanism components listed in LRA Table 3.1.2-1 which have been detected and evaluated to date in accordance with ASME [American Society of Mechanical Engineers] Code Section XI requirements, please propose a plan to monitor and evaluate these flaws during the period of extended operation because disposition of these detected flaws to date was based on a period of 40 years of operation. This plan should include monitoring and evaluating detected underclad flaws exceeding 0.3 inch in depth, the maximum initial flaw depth that was evaluated in WCAP-15338, "A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants."

Original I&M Response to RAI 3.1-8:

In accordance with ASME Section XI, Subarticle IWB-3600, analytical evaluation of reportable flaws (defects) requires that flaw growth be considered for an evaluation period equal to the time of the next inspection following discovery of the flaw, or until the end of the service life of the item. As reported in LRA Table 4.1-2, inservice inspection records indicated no defects that required analytical evaluation of flaws to the end of the service life of the component.

Inspection and evaluation of the control rod drive mechanism nozzles for continued service is addressed by the Control Rod Drive and Other Vessel Head Penetration Program discussed in LRA Section B.1.9.

Resolution of underclad cracking for CNP is discussed in LRA Section 4.7.4. The CNP reactor vessels do not contain SA-508, Class 2, forgings in the beltline regions. Only the vessel and closure head flanges and inlet and outlet nozzles are fabricated from SA 508, Class 2, forgings. The analytical evaluation contained in WCAP-15338 has been used to demonstrate that fatigue growth of the subject flaws will be minimal over 60 years and the presence of underclad cracks are of no concern relative to the structural integrity of the vessels. Based on this evaluation, additional inspections to detect and monitor crack growth during the period of extended operation are not required, and the analysis of underclad cracking remains valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). Therefore, an aging management program in accordance with 10 CFR 54.21(c)(1)(iii) is not required to manage underclad cracking.

Clarification Requested by the Staff:

Response to this RAI concludes, "inservice inspection records indicated no defects that required analytical evaluation of flaws to the end of the service life of the component." This could mean any of the following, please clarify.

- *Inservice inspection records indicated no defects.*
- *Inservice inspection records indicated defects, but none required analytical evaluations per Section XI of the ASME Code.*
- *Inservice inspection records indicated defects, and continued operations were approved by the NRC based on analytical evaluations per Section XI of the ASME Code. If this is the case, how many years of operation that the analytical evaluations assume?*

I&M's Supplemental Response to RAI 3.1-8:

In accordance with ASME Section XI, Paragraph IWB-3132, components that contain flaws that are rejected (i.e., defects, which are flaws that exceed the acceptance standards specified in Table IWB-3410-1) may be repaired (Subparagraph IWB-3132.2), replaced (Subparagraph IWB-3132.3), or shown to be acceptable for service by analytical evaluation (Subparagraph IWB-3132.4). Analytical evaluation may include an assessment of growth of the rejected flaw (defect) until: (1) the next inspection, or (2) the end of the service lifetime of the component. A review of inservice inspection records determined that CNP has no rejected flaws that were accepted by analytical evaluation to the end of the service lifetime of the component.

RAI 4.7.4-1:

The LRA Section 4.7.4, "Reactor Vessel Underclad Cracking," states, "The numbers of design cycles and transients assumed in the WCAP-15338 analysis bound the number of design cycles and transients projected for 60 years of operation." Please provide information regarding how you arrived at this conclusion.

Original I&M Response to RAI 4.7.4-1:

WCAP-15338-A, dated October 2002, includes the types and numbers of reactor coolant system (RCS) design transients utilized for evaluation of underclad cracking flaw growth over 60 years of operation. For CNP, the types and numbers of RCS design transients, with the exception of the feedwater cycling at hot shutdown, were verified to be bounded by the design transients assumed in WCAP-15338-A, thereby satisfying Renewal Applicant Action Item (1) of the Revised Safety Evaluation Report of WCAP-15338, dated September 25, 2002 [Accession No. ML022690375]. The feedwater cycling at hot shutdown transient is associated with a feedwater nozzle cracking concern and is not monitored at CNP due to design and operating modifications to preclude feedwater nozzle cracking. This transient is not anticipated to have a significant impact on crack growth beneath the reactor vessel cladding. CNP's projected number of RCS design transients for 60 years, as shown in LRA Table 4.3-1, does not exceed applicable design assumptions assumed in WCAP-15338-A. Therefore, the WCAP-15338-A RCS transients bound the CNP RCS transients, and WCAP-15338-A remains applicable to CNP for the period of extended operation.

Clarification Requested by the Staff:

Response to this RAI concludes that WCAP-15338-A remains applicable to CNP for the period of extended operation. However, LRA Section 4.7.4 states, "[t]herefore, the analysis of underclad cracking for CNP remains valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i)." Since the WCAP analysis is for 60 years, the appropriate paragraph for 10 CFR should be 10 CFR 54.21(c)(1)(ii). Please identify the appropriate citation.

I&M's Supplemental Response to RAI 4.7.4-1:

The criterion for 10 CFR 54.21(c)(1)(i) applicability is that the applicant shall demonstrate that time-limited aging analyses (TLAAs) remain valid for the period of extended operation. When developing the LRA, WCAP-15338-A was the analysis of record for CNP reactor vessel underclad cracking. Because the numbers of CNP design transients projected for 60 years of operation are bounded by (i.e., less than) the numbers of design transients assumed in the WCAP analysis, the analysis remains valid for the period of extended operation. On this basis, I&M identified 10 CFR 54.21(c)(1)(i) as appropriate for this TLAA. However, I&M concurs that the criterion for 10 CFR 54.21(c)(1)(ii) could also be considered applicable based on the approach used in applying the WCAP projection to CNP's design transient numbers. Therefore, either citation, 10 CFR 54.21(c)(1)(i) or 10 CFR 54.21(c)(1)(ii), is appropriate for the evaluation of this TLAA.

RAI B.1.5-2:

LRA Section B.1.5 provides the acceptance criteria of BMI [bottom-mounted instrumentation] thimble tubes as: (1) replacement or isolation of a thimble tube with 80 percent through-wall wear, (2) reposition of a thimble tube with more than 40 percent through-wall wear, provided that it is projected to remain under 80 percent until the next inspection, and (3) replacement, isolation, or reposition of a thimble tube with more than 40 percent through-wall wear if it is projected to exceed 80 percent by the next inspection. Using reposition as an option for Criterion 3 for a tube which is projected to exceed 80-percent wear by the next inspection is inadequate because the uncertainty of the tube wear rate at the selected location for the tube reposition in a certain time period might make the reposition ineffective. Provide a revision of the AMP [aging management program] by incorporating ET [eddy current testing] uncertainty in future wear measurements and by considering only replacement and isolation of tubes as options for Criterion 3 of the acceptance criteria.

Original I&M Response to RAI B.1.5-2:

The BMI inspection is based on recommendations provided in WCAP-12866, *Bottom Mounted Instrument Flux Thimble Wear.* The WCAP demonstrates that thimble tube percent wall loss varies at different core locations over several operating cycles. The current inspection procedure permits relocation of a BMI thimble tube from a location with wear predicted to equal or exceed 80% through-wall by the next inspection to a location that would not result in 80% wear by the next inspection. Therefore, a thimble tube can be repositioned to a core location that has historically demonstrated little or no thimble tube wall loss. The final relocation position of a thimble tube predicted to exceed 80% wear will be determined via the corrective action evaluation of the eddy current results. Alternatively, the affected thimble tube may be replaced or isolated. The use of WCAP-12866 for the BMI thimble tube inspection program basis is consistent with the McGuire and Catawba Nuclear Stations LRA in which the Corrective Action and Confirmation Process program element of the Bottom-Mounted Instrumentation Thimble Tube Inspection Program states: "Thimble tubes that are predicted to exceed the acceptance criteria may be capped or repositioned. Specific corrective actions and confirmatory actions are implemented in accordance with the corrective action program." This position was accepted by the staff in NUREG-1772, *Safety Evaluation Report Related to the License Renewal of McGuire Nuclear Station, Units 1 and 2, and Catawba Nuclear Station, Units 1 and 2.*

<u>Reference for RAI B.1.5-2</u>

Letter from E. E. Fitzpatrick, I&M, to NRC Document Control Desk, "Donald C. Cook Nuclear Plant, Units 1 and 2, Response to Confirmatory Action Letter No. RIII 97-011 NRC Architect Engineer (AE) Design Inspection August 1997," AEP:NRC:1260G3, dated December 2, 1997.

Clarification Requested by the Staff:

Please confirm that for thimble tubes that are repositioned, the final relocation position is selected based on plant-specific data. Elaborate on how you are going to establish the plant-specific wear rate for each thimble.

I&M's Supplemental Response to RAI B.1.5-2:

Thimble tube wear that exceeds 40% through-wall, as identified by the Bottom-Mounted Instrumentation Thimble Tube Inspection Program, will be evaluated in accordance with the Corrective Action Program. A thimble tube may be repositioned if wear exceeds 40%. Repositioning is determined using plant-specific operating experience (i.e., observed wear, as determined by eddy current testing, and accumulated time data) to predict wear at the relocation position to ensure that the repositioned tube wear will not exceed 80% by the next inspection. The predicted wear is determined by applying the plant-specific eddy current testing results to the equation on page 178 of WCAP-12866, assuming a conservative "n" value of 0.67. Thimble tubes that have been repositioned once may not be repositioned again.

RAI B.1.24-2:

The spray head and its associated components covered by LRA Section B.1.24 may be subject to severe thermal cycling. Inadequate justification was provided to demonstrate that a VT-3 *examination is sufficient to detect a potential flaw in the spray head which could lead to failure of the component. Provide justification for using VT-3 examination instead of VT-1 examination for the one-time inspection of these components in either Unit 1 or Unit 2. In addition, provide information regarding acceptance criteria; the evaluation methodology for disposition of indications; and the need for successive examinations for the one-time inspection of spray head, spray head locking bar, and coupling. Also, please provide your commitment in the commitment list and in the UFSAR [Updated Final Safety Analysis Report] Supplement.*

Original I&M Response to RAI B.1.24-2:

The pressurizer spray head and associated components are not pressure-retaining items. The primary aging effect of concern is cracking. Reduction of fracture toughness of the cast austenitic stainless steel (CASS) spray head may contribute to accelerated crack growth. The one-time visual inspection (VT-3) of the spray head will detect cracking. If cracks are detected in the spray head, engineering analysis will determine corrective actions, which could include follow-up examinations or replacement of the spray head. The acceptance standards for the visual examinations will be in accordance with ASME Section XI VT-3 examinations. This approach is consistent with the Oconee Nuclear Station (ONS) Pressurizer Examinations Program for CASS spray heads, as accepted by the Staff in NUREG-1723, *Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station, Units 1, 2, and 3*, in Section 3.4.3.3 on page 3-115. As summarized in the ONS Safety Evaluation Report (SER), the Staff expects cracking of the spray head to be a slow acting aging effect and expects minimal cracking, if any, to be found. The use of a one-time visual inspection (VT-3) to detect cracking was found to be adequate for the ONS spray heads, which are similar in design and function to the CNP pressurizer spray heads.

The acceptance criteria and corrective actions to disposition identified flaws are currently stated in LRA Section B.1.24, and the related commitments are listed in Attachment 1 to the referenced LRA submittal letter. The LRA UFSAR Supplement also includes the commitment to complete a one-time inspection of the spray head and associated components. LRA Section A.2.1.27 states: "This program will also determine the condition of the internal spray head, spray head locking bar, and coupling by a one-time visual examination of these components in one CNP unit. This program requires enhancements that will be implemented prior to the period of extended operation." This description is consistent with the level of detail in other LRA Appendix A program descriptions. Because LRA Attachments A and B provide the requested information and commitments, no additional changes are required.

Reference for RAI B.1.24-2

Letter from M. K. Nazar, I&M, to NRC Document Control Desk, "Donald C. Cook Nuclear Plant, Units 1 and 2, Application for Renewed Operating Licenses," AEP:NRC:3034, dated October 31, 2003 [Accession No. ML033070177].

Clarification Requested by the Staff:

If the CNP Appendix R evaluation credits the spray pattern provided by the pressurizer spray heads, visual examinations of the spray heads performed to VT-3 examination methods may not be adequate. Please confirm pressurizer spray is credited in the CNP Appendix R analysis, and if so, provide the basis for determining VT-3 examinations will be sufficient to ensure the spray heads will be capable of performing their intended functions through the period of extended operation.

I&M's Supplemental Response to RAI B.1.24-2:

The CNP Safe Shutdown Capability Assessment notes that following an Appendix R fire, much of the equipment that would normally be available to control RCS pressure and inventory (including pressurizer heaters, normal and auxiliary spray flow, the reactor head vents, and equipment required for all modes of letdown) may not be available and is not credited for post-fire safe shutdown. Thus, the plant's available capability to cool down and de-pressurize is accomplished by controlling pressure with the pressurizer power-operated relief valves (PORVs) and controlling cooldown through heat rejection by the steam generator PORVs, while maintaining reactor coolant pump seal injection flow to assure seal integrity.

LRA Table 3.1.2-4 conservatively identified "Pressure control" as a license renewal intended function that is satisfied by the pressurizer spray components (pressurizer spray head, spray head locking bar, and spray head coupling). Upon further review, I&M determined that the pressurizer spray components, while utilized for pressure control during normal plant operation, are not relied upon for the mitigation of design basis events, would not prevent satisfactory accomplishment of a design basis event should they fail, and are not required to demonstrate compliance with the regulated events (including fire protection, as discussed above). Therefore, the spray heads and associated components do not perform a license renewal intended function and are not required to satisfy the safety-related systems, structures, or components scoping criteria of 10 CFR 54.4(a)(1), the nonsafety-related scoping criteria of 10 CFR 54.4(a)(2), or the regulated events scoping criteria of 10 CFR 54.4(a)(3).

Although these components do not perform a license renewal intended function and are not subject to aging management review, I&M still plans to enhance the Pressurizer Examinations Program to perform a one-time VT-3 visual examination of these components in one unit as part of the CNP license renewal commitments. The purpose of this one-time examination is to assess the condition of the spray head, spray head locking bar, and couplings to determine if any corrective actions, including replacement, should be implemented. Additionally, I&M will consider the results of this one-time examination to determine if subsequent examinations should be performed. As discussed in the original I&M response to RAI B.1-24-2, VT-3 examination is adequate to detect cracking of the pressurizer spray head and associated components, which is a slow-acting aging effect. Use of a one-time VT-3 examination is sufficient to detect cracking and is consistent with the examination method and frequency accepted by the NRC Staff for Oconee Nuclear Station in NUREG-1723.

RAI B.1.26-2:

GALL Program XI.M31 lists 8 items of consideration for an acceptable reactor vessel surveillance program. Item 4 indicates that all pulled and tested capsules, unless discarded before August 31, 2000, are placed in storage. Please provide information regarding consistency with GALL with respect to this item. Also, the staff noticed that Item 6 indicates that all other standby capsules exceeding equivalent RPV fluence of 60 EFPY [effective full power years] are to be removed and placed in storage. Please provide the projected dates (in terms of RPV EFPY) for all standby capsules (Capsules V and Z for Unit 1 and Capsules V, W, and Z for Unit 2) to reach the fluence equivalent to 60 EFPY of RPV fluence and the plan to remove and store these standby capsules.

Response to RAI B.1.26-2:

(NOTE: In a public meeting conducted on October 5, 2004, the NRC Staff clarified that reference to 60 EFPY in RAI B.1.26-2 should be interpreted as 60 years of operation, not 60 EFPY.)

Consistent with NUREG-1801, Section XI.M31, Item 4, I&M will place all capsules that are pulled and tested after August 31, 2000, in storage. CNP has not pulled any capsules after August 31, 2000.

After pulling one capsule at 32 EFPY, both units will have three standby capsules with lead factors of 1.23 and 1.22 as reported in Section 7 of WCAP-12483, *Analysis of Capsule U from the American Electric Power Company D. C. Cook Unit 1 Reactor Vessel Radiation Surveillance Program,* Revision 1, for Unit 1 and WCAP-13515, *Analysis of Capsule U from the Indiana Michigan Power Company D. C. Cook Unit 2 Reactor Vessel Radiation Surveillance Program,* Revision 1, for Unit 2, respectively. As specified in LRA Section B.1.26, I&M will pull and test one standby capsule for each unit between 32 EFPY and 48 EFPY to address the peak fluence expected at 60 years. If the standby capsules are kept in their current position, the withdrawal of one capsule in each unit to satisfy the 60 year (48 EFPY) fluence requirement in NUREG-1801, Section XI.M31, will occur at approximately 40 EFPY. Because the lead factors for the remaining standby capsules are slightly above 1.0, I&M plans to keep the remaining standby capsules in the vessel should I&M decide to pursue a second license renewal term (i.e., operation to 80 years). As required by 10 CFR 50, Appendix H, I&M will comply with American Society for Testing and Materials (ASTM) E 185-82, Table 1, which requires that the standby capsule fluence not be less than once or greater than twice the peak end-of-life vessel fluence. In addition, 10 CFR 50, Appendix H, requires that any revisions to the capsule withdrawal schedule be reported to the NRC in accordance with 10 CFR 50.4.

RAI B.1.27-1:

Because of the limited information provided in LRA Section B.1.27, "Reactor Vessel Internals Plates, Forgings, Welds, and Bolting," the staff could not verify that this program is consistent with GALL for most of the 10 elements. For example, the LRA does not mention the identification of the most susceptible items, an Attribute 1 concern; the specific water chemistry guidelines used, an Attribute 2 concern; and whether enhanced visual VT-1 examinations or ultrasonic testing will be employed in inspections for certain selected components and locations, an Attribute 4 concern. Provide information regarding whether all 10 elements of the program are in accordance with GALL Program XI.M16, "PWR Vessel Internals," and whether your program contains any exceptions or enhancements.

Summary of Original I&M Response to RAI B.1.27-1:

As stated in LRA Section B.1.27, the Reactor Vessel Internals Plates, Forging, Weld, and Bolting Program will be consistent with the program described in NUREG-1801, Section XI.M16, "PWR Vessel Internals." In accordance with the standard LRA format, the information provided in LRA Section B.1.27 is consistent with the level of detail provided for all programs that are consistent with NUREG-1801. There are no exceptions to the NUREG-1801 program. As identified in LRA Section B.1.27...one enhancement to the NUREG-1801, Section XI.M16, program is applicable.

The remainder of the response provided the requested information of the 10 Aging Management Program Elements of the Reactor Vessel Internals Plates, Forging, Weld, and Bolting Program.

Clarification Requested by the Staff:

In the response to RAI B.1.27-1, the applicant did not specify the visual inspection technique to be used in the implementation of this AMP. Please confirm that this AMP will include the Materials Reliability Program (MRP) recommendations, including the appropriate visual inspection technique (e.g., enhanced VT-1 with a 0.0005-inch resolution currently specified in GALL), to be used for inspections performed under this AMP.

In the response to RAI B.1.27-1 regarding Acceptance Criteria, the applicant states, "For the plates, forgings, welds, and bolting other than baffle bolts that will be visually inspected, critical flaw size will be determined by analysis prior to inspection." This did not mention the acceptance criteria for the analysis. GALL requires the use of IWB-3400 and IWB-3500 as the acceptance criteria for flaw analysis (evaluation). Please clarify.

I&M's Supplemental Response to RAI B.1.27-1:

For the plates, forgings, welds, and bolting, other than baffle bolts, that will be visually inspected by the Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program, critical crack size will be determined by analysis prior to inspection. The CNP acceptance criteria will be consistent with NUREG-1801. The appropriate visual acuity requirements for augmented visual inspection of components, other than baffle bolts, will be based in part on the critical crack size analysis. It is anticipated that augmented visual inspection may require VT-1 or enhanced VT-1 (defined in NUREG-1801, Section XI.M-19, as the ability to achieve a 0.0005-inch resolution). As discussed in LRA Section B.1.27, CNP will adopt appropriate MRP recommendations in the Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program; this would include recommendations related to techniques for augmented visual inspections (including acuity requirements) conducted under this program.

The augmented inspections for reactor vessel internals plates, forgings, welds, and bolting, other than baffle bolts, will compare inspection results with the appropriate acceptance standards of ASME Section XI, Subarticles IWB-3400 and IWB-3500, which is consistent with NUREG-1801, Section XI.M16. Note that the acceptance standards contained in ASME Section XI, Subarticle IWB-3500, may not apply to specific reactor vessel internals items that require augmented inspection. In that case, alternate acceptance standards suggested by the MRP may be used.

RAI B.1.27-2:

The information provided in LRA Section B.1.27 is insufficient for the staff to determine whether the PWR [pressurized water reactor] Materials Reliability Project (MRP) Issues Group and Westinghouse Owners Group (WOG) programs discussed there address all key issues of this aging management program (AMP), i.e., crack initiation and growth due to stress corrosion cracking (SCC) or irradiation-assisted SCC, loss of fracture toughness due to neutron irradiation embrittlement, and distortion due to void swelling. Provide a description of all the tasks under the MRP program and their goals and an assessment of the relevance of these tasks to the three aging effects mentioned above. Provide the same for the WOG program for baffle and former bolting. Further, your participation in the MRP program should be included as a commitment in your LRA commitment list and in the UFSAR Supplement to be submitted to the NRC. Also, please provide a commitment that the program to manage void swelling will be submitted for staff review and approval three years prior to the period of extended operation.

Clarification requested for RAI B.1.27-2:

In the original response to RAI B.1.27-2, I&M revised the Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program commitment made in the LRA to state that the program to manage void swelling will be submitted for staff review and approval three years prior to the period of extended operation. In a public meeting conducted on October 5, 2004, the NRC Staff clarified the original RAI as follows:

Please provide a commitment that the Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program will be submitted for staff review and approval three years prior to the period of extended operation.

I&M's Supplemental Response to RAI B.1.27-2:

I&M will submit the Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program for NRC Staff review and approval three years prior to the period of extended operation.

Auxiliary Systems – Aging Management Review and Programs

RAI 2.3.3.8-6:

The failure of the following components could affect the ability of their associated EDG [emergency diesel generator] to perform its intended function and are therefore in the scope of license renewal for meeting criteria 10 CFR 54.4(a)(2):

- *Exhaust silencer QT-104-AB and associated vent stack on LRA-1-5151B-0 at Location N7/8*
- *Exhaust silencer QT-104-CD and associated vent stack on LRA-1-5151D-0 at Location N7/8*
- *Exhaust silencer QT-104-AB and associated vent stack on LRA-2-5151B-0 at Location N6/7*
- *Exhaust silencer QT-104-CD and associated vent stack on LRA-2-5151D-0 at Location N6/7*

The exhaust silencers and associated vent stacks are long-lived passive components and are therefore subject to an AMR [aging management review].

The applicant is requested to confirm that the exhaust silencers and associated vent stacks are in scope and subject to an AMR and identify which "component type" on LRA Table 2.3.3-8 represents them or provide justification for their exclusion.

Original I&M Response to RAI 2.3.3.8-6:

The EDG exhaust silencers and associated vent stacks are nonsafety-related components whose only functions are to limit the noise created by the diesel engine and complete the transport of exhaust gas to the atmosphere. These components do not perform a function that meets the scoping criteria of 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3). Because they are located outside the EDG rooms and contain air and exhaust gases, they cannot impact safety-related components through spatial interaction as discussed in LRA Section 2.1.1.2.2, and do not meet the scoping criteria of 10 CFR 54.4(a)(2). Therefore, the EDG exhaust silencers and vent stacks are not subject to aging management review.

Clarification requested for RAI 2.3.3.8-6:

The failure of the following components could affect the ability of their associated EDG to perform its intended function and are therefore in the scope of license renewal for meeting criteria 10 CFR 54.4(a)(2):

- *Exhaust silencer QT-104-AB and associated vent stack on LRA-1-5151B-0 at Location N7/8*

- *Exhaust silencer QT-104-CD and associated vent stack on LRA-1-5151D-0 at Location N7/8*
- *Exhaust silencer QT-104-AB and associated vent stack on LRA-2-5151B-0 at Location N6/7*
- *Exhaust silencer QT-104-CD and associated vent stack on LRA-2-5151D-0 at Location N6/7*

The exhaust silencers and associated vent stacks are long-lived passive components and are therefore subject to an AMR.

The applicant is requested to confirm that the exhaust silencers and associated vent stacks are in scope and subject to an AMR and identify which "component type" on LRA Table 2.3.3-8 represents them or provide justification for their exclusion.

The applicant is requested to justify why this component is not included within AMR.

I&M's Supplemental Response to RAI 2.3.3.8-6:

I&M understands the NRC Staff's concern, as presented in a September 1, 2004, public meeting, to be that degradation of the EDG exhaust silencer internals could cause the internals to fail. It was postulated that failure of the internals could partially or completely block the exhaust flow, thereby preventing the EDG from achieving the required power output. The silencer internals consist of carbon steel vertical tubes, baffles, and supports. An I&M engineering evaluation, supported by a vendor assessment, determined that the EDG exhaust silencer internals are designed such that it is not likely that a failure of the internals could restrict flow through the exhaust silencer, thereby rendering the EDG inoperable.

As stated by the Commission in the Statements of Consideration for the Final Part 54 Rule, "An applicant for license renewal should rely on the plant's CLB [current licensing basis], actual plant-specific experience, industry-wide operating experience, as appropriate, and existing engineering evaluations to determine those nonsafety-related systems, structures, and components that are the initial focus of the license renewal review. Consideration of hypothetical failures that could result from system interdependencies that are not part of the CLB and that have not been previously experienced is not required."

A review of plant and industry operating experience did not find any exhaust silencer failures that resulted in a loss of EDG intended function. In addition, the EDGs are only operated for short periods of time during normal plant operation, so loss of material of the exhaust silencer internals would be minimal even over 60 years of operation. As previously stated in I&M's original response to RAI 2.3.3.8-6 above, the EDG exhaust vent silencers do not support an intended function identified in 10 CFR 54.4 and are not subject to aging management review. Therefore, because the EDG exhaust vent silencers do not perform an intended function, and based on the low likelihood of hypothetical age-related failures and a focused review of operating experience, I&M concludes that the EDG exhaust silencers do not meet the 10 CFR 54.4 scoping criteria. However, to facilitate the NRC Staff's review, I&M will conservatively subject the EDG exhaust silencers to aging management.

Only the internals of the EDG exhaust silencers are subject to aging management. The silencer internals are exposed to air and exhaust gas environments. The Preventive Maintenance Program will manage loss of material for the EDG exhaust silencer internals. Visual inspections of the EDG exhaust silencer internals will be performed before the period of extended operation as part of the Preventive Maintenance Program. The frequency of future inspections will be based on the initial inspection results.

RAI 3.3.2.1.4-1:

Table 3.3.2-4, page 3.3-49, identifies change in material properties and cracking as AERMs [aging effects requiring management] for elastomer flex hose components in an internal treated air environment. The Preventive Maintenance AMP, B.1.25, page B-82 of the LRA, is credited in managing these aging effects by periodic visual inspections and replacement as necessary. It is not apparent from the program description if the flex hoses will be inspected both internally and externally. It is also not apparent how effective a visual inspection will be in detecting internal changes in material properties and cracking. Provide justification that the Preventive Maintenance AMP, B.1.25, will adequately identify and manage the identified internal aging effects.

Original I&M Response to RAI 3.3.2.1.4-1:

The elastomer flex hoses listed in LRA Table 3.3.2-4 are control air system rubber hoses located in containment. These hoses are exposed to treated air internally and ambient air externally. Degradation of rubber from cracking and change in material properties can be due to ultraviolet radiation, ionizing radiation or thermal exposure. The external and internal hose surfaces are exposed to the same environmental conditions, with the exceptions that the air environments differ and the internal hose surfaces are not exposed to ultraviolet radiation, since they are not exposed to light.

Clarification Requested by the Staff:

The applicant's response to the RAI 3.3.2.1.4-1 does not provide adequate information to substantiate aging management of these components by external visual observation only. The applicant is requested to substantiate the adequacy of external surface visual examination in managing aging by providing details related to the applicable component's inspection/failure/repair frequency experienced during the plants operating history. Also, AMP B.1.25 does not provide an inspection frequency for the hoses such that the intended function will be maintained.

I&M's Supplemental Response to RAI 3.3.2.1.4-1:

A review of the operating experience for these hoses did not identify any pressure boundary failures due to elastomer degradation. However, prior to the period of extended operation, I&M will inspect internal hose ends and external surfaces of the in-containment control air system rubber hoses referred to in LRA Table 3.3.2-4. The periodicity of future inspections will be based on the condition of the hoses in relation to their time-in-service.

RAI 3.3.2.1.9-1:

Table 3.3.2-9, page 3.3-115 and page 3.3-120, identifies loss of material as an aging effect of stainless steel fittings and stainless steel/carbon steel piping in a soil environment. The applicant identifies System Testing, B.1.37, page B-114, as an applicable AMP for managing these aging effects. System Testing, B.1.37, does not define fitting or pipe condition or approximate rate of degradation as recommended in NUREG-1801, XI.M28 or XI.M34 for buried fittings/piping. Provide justification for exclusion of buried piping/fitting condition assessment in B.1.37 in accordance with NUREG-1801 or revise the AMP accordingly.

Original I&M Response to RAI 3.3.2.1.9-1:

The items referred to in LRA Table 3.3.2-9 are associated with the security diesel underground fuel oil tank and associated underground piping and fittings. The security diesel underground fuel oil tank and associated underground piping and fittings are periodically tested for leakage using timed system pressure tests. Leakage above the acceptance criteria or other degraded conditions would be discovered such that corrective actions can be taken prior to loss of the system intended functions.

Clarification Requested by the Staff:

Based on its review, the staff is not able to find the applicant's response to RAI 3.3.2.1.9-1 acceptable. The applicant's response indicates that leakage above acceptance criteria or other degraded conditions would be discovered using periodic leakage test allowing time for corrective actions prior to loss of system intended function. Although leakage tests define the underground piping systems' integrity at a snapshot in time, they may not be reflective of the piping and associated components' actual condition and rate of degradation during the period of extended operation. The applicant describes an underground tank and piping inspection program (Buried Piping Inspection, AMP B.1.6, page B-31 of the LRA) that appears to provide the necessary actions to quantify current piping condition and estimate a rate of degradation over period of operation for components such as the security diesel underground components. Provide justification that leak rate test results reflect actual rate of degradation and current condition of underground piping and fittings as defined in Table 3.3.2-9. Justify not utilizing an aging management program similar to AMP B.1.6, Buried Piping Inspection Program, in *managing aging effects associated with buried carbon steel and stainless steel piping, tanks, and fittings defined in Table 3.3.2-9.*

I&M's Supplemental Response to RAI 3.3.2.1.9-1:

The security diesel underground fuel oil tank and associated underground piping and fittings referred to in LRA Table 3.3.2-9 will be included in the Buried Piping Inspection Program described in LRA Section B.1.6.

In LRA Section 3.3.2.19, on Page 3.3-14, the Buried Piping Inspection Program should be added to the Aging Management Programs listing.

In LRA Section 3.3.2.2.11, on Page 3.3-20, the discussion should be revised to add the *italicized* text and delete the strikethrough text as follows:

> This paragraph of NUREG-1800 discusses the potential for loss of material in buried piping of the service water and diesel fuel oil systems. There are no buried components in the CNP essential service water system. The Buried Piping Inspection Program will manage loss of material for buried components of the diesel fuel oil system~~. For~~ *and* buried components of the security diesel *system*~~, the System Testing Program will manage loss of material~~.

In LRA Table 3.3.1, the Discussion section entry for Item Number 3.3.1-18 on Page 3.3-28 should be revised to add the *italicized* text and delete the strikethrough text as follows:

> Consistent with NUREG-1801; for the emergency diesel generators *and the security diesel*, the Buried Piping Inspection Program will manage loss of material for buried components. ~~For the security diesel, the System Testing Program will manage loss of material for buried components.~~

In LRA Table 3.3.2-9, the aging management program credited for managing aging effects of Component types "Fittings," "Piping," "Tank," and "Tubing" that are exposed to a "Soil (external)"environment, as listed on Pages 3.3-115, 3.3-116, 3.3-120, 3.3-122, and 3.3-123, should be revised from "System Testing" to "Buried Piping Inspection" and the Table 1 Item and Notes column entries should be revised as shown on the Table 3.3.2-9 excerpts provided on the next page.

In LRA Section B.1.37, the *Security Diesel System Test* section on Pages B-115 and B-116 should be revised to delete the strikethrough text as follows:

"Security Diesel System Test

Testing requirements include periodically starting the security diesel and operating it in accordance with manufacturer's recommendations. System testing is credited for managing fouling and loss of material for the security diesel jacket water heat exchangers and lube oil heat exchangers.

Since periodic engine testing and inspections are performed on the security diesel, system testing is also credited for managing loss of material for the following:

- ~~Buried fuel oil storage tank,~~
- ~~Pipe,~~
- ~~Tubing/fittings,~~
- Starting air components, and
- Exhaust gas components.

~~Fuel oil level indication and periodic pressure testing with use of the spectacle flange manage the aging effects on the buried fuel oil storage tank.~~ During engine operation, monitoring engine parameters and performing visual inspections manage the aging effects by verifying the pressure boundary of engine components. Also, six-month and annual inspections are performed on the security diesel to manage the aging effects on security diesel passive mechanical components."

I&M's Supplemental Response to RAI 3.3.2.1.9-1 (continued):
[Note: revised entries are in *italics.*]

Excerpts from LRA Table 3.3.2-9: Security Diesel

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG- 1801 Vol. 2 Item	Table 1 Item	Notes
Fittings	Pressure boundary	Carbon steel	Soil (external)	Loss of material	*Buried Piping Inspection*	VII. H1.1-b	3.3.1-18	*B*
		Copper alloy	Soil (external)	Loss of material	*Buried Piping Inspection*	*VII. H1.1-b*	*3.3.1-18*	*B*
Fittings (continued)	Pressure boundary	Stainless steel	Soil (external)	Loss of material	*Buried Piping Inspection*	*VII. H1.1-b*	*3.3.1-18*	*B*
Piping (continued)	Pressure boundary	Carbon steel	Soil (external)	Loss of material	*Buried Piping Inspection*	VII. H1.1-b	3.3.1-18	*B*
		Stainless steel	Soil (external)	Loss of material	*Buried Piping Inspection*	*VII. H1.1-b*	*3.3.1-18*	*B*
Tank	Pressure boundary	Carbon steel	Soil (external)	Loss of material	*Buried Piping Inspection*	VII. H1.1-b	3.3.1-18	*B*
Tubing	Pressure boundary	Carbon steel	Soil (external)	Loss of material	*Buried Piping Inspection*	VII. H1.1-b	3.3.1-18	*B*

RAI 3.3.2.1.9-4:

Table 3.3.2-9, page 3.3-119, identifies the System Testing, B.1.37, page B-114 of the LRA, as being credited in managing loss of material of copper alloy heat exchanger tube components in a treated water external environment. For the same environment, component, and material, the Table 3.3.2-8, page 3.3-102, identifies Heat Exchanger Monitoring and Water Chemistry Control AMPs to manage loss of material and loss of material-wear. Justify the exclusion of Water Chemistry Control and Heat Exchanger Monitoring AMPs in managing the security diesel heat exchanger tube pressure boundary function in Table 3.3.2-9.

Original I&M Response to RAI 3.3.2.1.9-4:

The security diesel is a non-seismic, nonsafety-related system. Since a major component of the Heat Exchanger Monitoring Program will be monitoring the seismic qualification of heat exchangers, this program is not credited for the non-seismic security diesel engine coolant heat exchangers or lube oil coolers. The security diesel engine coolant heat exchanger shell internal surfaces and tube external surfaces are exposed to treated water from the Lake Township water system. Lake Township water chemistry is not included in a Water Chemistry Control Program. Consequently, neither the Heat Exchanger Monitoring Program, nor the Water Chemistry Control Program would be appropriate for managing loss of material in these heat exchanger tubes.

The security diesel engine lube oil cooler shell internal surfaces and tube external surfaces are exposed to lube oil, which is monitored by the Oil Analysis Program, as described in LRA Section B.1.23. The Oil Analysis Program detects and controls contaminants (primarily water and particulates), thereby preserving an environment that is not conducive to corrosion, cracking, or fouling. Presence of engine coolant in the lube oil would be indicative of degradation of the lube oil cooler tubes. Additionally, during the periodic security diesel testing in accordance with the System Testing Program, operating parameters, such as oil pressure and jacket water temperature, are monitored. Abnormal indications and failure to meet acceptance criteria would result in corrective action being taken. Therefore, since the Oil Analysis and System Testing Programs monitor the parameters that would provide an indication of unacceptable aging effects, these programs are adequate for managing the effects of aging on the security diesel heat exchangers.

Clarification Requested by the Staff:

The applicant is requested to provide further justification for exclusion of Water Chemistry Control Program and Heat Exchanger Monitoring Program in managing the security diesel lube oil heat exchanger. The applicant is further requested to justify differences in aging management of security diesel heat exchangers and emergency diesel generator heat exchangers.

The applicant's AMPs detect the loss of material aging effect only after heat exchanger degradation has resulted in loss of pressure boundary integrity between the heat exchanger shell and tube sides or changes in heat transfer properties. The applicant's response does not justify the omission of a Water Chemistry Control Program or Heat Exchanger Monitoring Program in management of security diesel heat exchangers. Provide justification why the security diesel heat exchanger's AMPs, as defined in Table 3.3.2-9, are as effective in management of the loss of material aging effect as those defined in NUREG-1801.

I&M's Supplemental Response to RAI 3.3.2.1.9-4:

The security diesel lube oil cooler is a shell and tube heat exchanger with lube oil internal to the shell and engine coolant (treated water) in the tubes. LRA Table 3.3.2-9 indicates that loss of material of copper alloy heat exchanger (tubes) in a treated water internal environment is managed by water chemistry control. The line item in the table excerpt from Page 3.3-119 shown below refers to the internal tube side of the security diesel lube oil cooler. The applicable aging management program is the Auxiliary Systems Water Chemistry Control Program, which is described in LRA Section B.1.40.3.

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat exchanger (tubes) (continued)	Pressure boundary	Copper alloy	Treated water (internal)	Loss of material	Water Chemistry Control			3

As indicated in LRA Tables 3.3-8 and 3.3-9 on Pages 3.3-102 and 3.3-118, respectively, loss of material of both the security diesel and EDG lube oil cooler tube external surfaces is managed by the Oil Analysis Program, which is described in LRA Section B.1.23.

Therefore, water chemistry control does manage loss of material of the security diesel lube oil cooler tube internal surfaces, and the Oil Analysis Program manages the security diesel and EDG lube oil cooler tube external surfaces. To verify that aging effects are not occurring, the Chemistry One-Time Inspection Program, which is described in LRA Section B.1.41, will be used to inspect the security diesel lube oil cooler tube internal surfaces.

There is no applicable comparison to NUREG-1801 for the security diesel lube oil heat exchanger tubes because NUREG-1801 does not evaluate these heat exchanger tubes or similar copper alloy components in a treated water environment. Furthermore, a comparison between the security diesel heat exchangers and EDG heat exchangers is not required, as the inclusion of the security diesel heat exchangers in the Chemistry One-Time Inspection Program will provide the necessary verification that loss of material of the heat exchanger tubes is not occurring.

RAI 3.3.2.1.9-6:

Table 3.3.2-9, page 3.3-118, identifies the System Testing AMP, B.1.37, to manage the loss of material on the internal surface of the security diesel heat exchanger shell in a treated water environment. The System Testing program manages these aging effects by periodically starting the security diesel and operating it in accordance with manufacturer's recommendations and monitoring system flow and system pressure. Describe how the System Testing program manages aging effects on the internal surfaces of the heat exchanger shell.

Original I&M Response to RAI 3.3.2.1.9-6:

Testing of the security diesel generator is performed to demonstrate operability of the security diesel and to demonstrate the security diesel fuel oil system's ability to perform its intended functions. In addition to monitoring system flow, pressure, and temperature, monitoring for abnormal conditions, such as leakage, is also performed during the conduct of these system tests. Malfunctioning equipment, leakage, or failures to meet acceptance criteria during system testing would result in corrective action being taken.

Loss of material on the treated water side of the heat exchanger shell would be detected in the form of pinhole leaks caused by isolated pitting or crevice corrosion. Monitoring for component leakage and system operating parameters under the System Testing Program provides assurance that loss of material from the internal surfaces of the heat exchanger shell will be identified during testing, prior to resulting in loss of function of the heat exchanger. This level of monitoring is commensurate with the safety significance of this non-seismic, nonsafety-related component.

Clarification Requested by the Staff:

The programs defined by the applicant to manage the security diesel's heat exchanger shell exposed to a treated water environment do not minimize aging effects to the same degree nor provide the same level of assurance in maintenance of the pressure boundary function. The applicant's AMPs detect the loss of material aging effect only after heat exchanger degradation has resulted in a detectable loss of pressure boundary integrity or changes in heat transfer properties. The applicant's response does not justify the omission of a Water Chemistry Control Program or Heat Exchanger Monitoring Program in management of security diesel heat exchangers. The applicant should provide justification why the security diesel heat exchanger's AMPs, as defined in Table 3.3.2-9, are as effective in managing the loss-of-material aging effect as those defined in NUREG-1801.

I&M's Supplemental Response to RAI 3.3.2.1.9-6:

The security diesel jacket water coolers are shell and tube heat exchangers with engine coolant (treated water) internal to the tubes and Lake Township water (treated water) internal to the shell.

Loss of material of the tube internal surfaces is managed by water chemistry control as indicated in the excerpt from Page 3.3-119 of LRA Table 3.3.2-9 provided below. The applicable aging management program is the Auxiliary Systems Water Chemistry Control Program, which is described in LRA Section B.1.40.3.

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat exchanger (tubes) (continued)	Pressure boundary	Copper alloy	Treated water (internal)	Loss of material	Water Chemistry Control			3

Because Lake Township water (shell internal and tube external environments) chemistry is not controlled by CNP, a chemistry control program was not credited in the LRA. However, Lake Township water is provided by a municipality that is a Michigan state-licensed public water supplier subject to provisions in the Michigan Department of Environmental Quality (MDEQ) *Safe Drinking Water Act 1976 PA 399, and Administrative Rules, as amended,* which include compliance with contaminant standards, and certification, monitoring, and reporting requirements. Lake Township water is potable water that has been treated with chemicals by the municipality. The municipality monitors contaminants such as chlorides and fluorides to maintain the water quality within MDEQ and Environmental Protection Agency regulations. Because the contaminant levels are maintained to ensure compliance with standards, significant aging effects are not expected. To verify the absence of significant aging effects, the Chemistry One-Time Inspection Program will include inspection of the surfaces of the security diesel jacket water coolers that are exposed to Lake Township water. The periodicity of further inspections will be based on the condition of the coolers in relation to their time-in-service.

There is no applicable comparison to NUREG-1801 for the security diesel jacket water coolers since neither these coolers, nor any similar components, are evaluated by NUREG-1801.

RAI 3.3.2.1.10-1:

Table 3.3.2-10, page 3.3-127, identifies the Preventive Maintenance Program, B.1.25, page B-82 of the LRA, as managing change in material properties and cracking of flex hoses with an internal environment of oxygen. The program states that it will manage these aging effects by visual inspection and replacement as necessary. It is not apparent from the program description if internal and external surfaces will be inspected. Due to different internal and external environmental conditions, external examination may not be representative of internal component condition. Explain how the visual examination referred to in the Preventive Maintenance Program, B.1.25, will ensure management of internal aging effects.

Original I&M Response to RAI 3.3.2.1.10-1:

The flex hoses listed in LRA Table 3.3.2-10 are small rubber hoses on the oxygen supply bottles. These bottles store pure oxygen, which is used as a reagent for the hydrogen analyzers. The hoses are exposed to oxygen internally and ambient air externally. Degradation of rubber from cracking and change in material properties can be due to ultraviolet radiation, ionizing radiation, or thermal exposure. The internal hose surfaces are not exposed to ultraviolet radiation, since they are not exposed to light. The supply bottles and hoses are installed in a low radiation area. Therefore, the component dose will be substantially lower than the radiation dose threshold for elastomers (10^6-10^7 Rad). Both internal and external hose surfaces are close to the ambient air temperature of the auxiliary building.

Since oxygen is also present in atmospheric (ambient) air, both internal and external surfaces of the hoses are exposed to oxygen. The external surface is exposed to an environment that is more severe than the internal environment (ultraviolet radiation); neither the internal nor external surfaces are exposed to elevated temperatures or high radiation. Therefore, inspection of the external surfaces is adequate to ensure detection of aging effects prior to loss of the pressure boundary intended function.

Clarification Requested by the Staff:

The applicant's response to RAI 3.3.2.1.10-1 does not provide adequate information to substantiate aging management of these components by external visual observation only. The applicant is requested to substantiate the adequacy of external surface visual examination in managing aging by providing details related to the applicable component's inspection/failure/repair frequency experienced during the plants operating history.

I&M's Supplemental Response to RAI 3.3.2.1.10-1:

A review of the operating experience for these hoses did not identify any pressure boundary failures due to elastomer degradation. However, prior to the period of extended operation, I&M will inspect internal hose ends and external surfaces of the post-accident hydrogen monitoring system reagent supply rubber hoses referred to in LRA Table 3.3.2-10. The periodicity of future inspections will be based on the condition of the hoses in relation to their time-in-service.

RAI 3.3.2.1.11-1:

Table 3.3.2-11, page 3.3-130 to 3.3-152, identifies the System Walkdown, B.1.38, page B-119 of the LRA, for management of various aging effects for several components with different internal and external environments. The System Walkdown Program, Section B.1.38 of the LRA, states that the program is only applicable to situations where the internal and external environment is the same. Component external condition may not be representative of internal material *conditions in differing environments. Justify utilization of the System Walkdown Program, B.1.38, in managing aging effects for all components identified in Table 3.3.2-11 with differing internal and external environments. Also explain how a system walkdown can inspect and verify proper management of all internal aging effects.*

Original I&M Response to RAI 3.3.2.1.11-1:

The statement in the LRA Section B.1.38 Scope section is, "The program is also credited with managing loss of material from internal surfaces, for situations where the external surface condition is considered representative of the internal surface condition and both have the same environment." This statement does not indicate that the System Walkdown Program is only applicable to situations where the internal and external environments are the same. The Scope section also states, "This program includes inspections of external surfaces of CNP structures and components within the scope of license renewal." This inspection of external surfaces addresses components subject to aging management review for 10 CFR 54.4(a)(2), as indicated in LRA Table 3.3.2-11, where the System Walkdown Program is credited as the sole aging management program regardless of the environment. For these components, the concern is the impact of spray or leakage from nonsafety-related components on safety-related equipment. Providing the effect of nonsafety-related component failures on safety-related equipment is managed, safety-related equipment will continue to be capable of performing its required intended functions.

The System Walkdown Program, as described in LRA Section B.1.38, manages aging through visual inspections of systems and components. This program includes periodic walkdowns that will detect and correct failures that could result in long-term exposure to spray or wetting. Short-term exposure is not a concern for passive components such as valve bodies and piping. Active safety-related component failures due to short-term exposure would be detected in the course of normal operation or through monitoring required by the Maintenance Rule and appropriate corrective actions would be taken to prevent recurrence. This is consistent with the NRC's position provided in the Statements of Consideration for the Final Part 54 Rule, which states, "On the basis of consideration of the effectiveness of existing programs which monitor the performance and condition of systems, structures, and components that perform active functions, the Commission concludes that structures and components associated only with active functions can be generically excluded from a license renewal aging management review. Functional degradation resulting from the effects of aging on active functions is more readily determinable, and existing programs and requirements are expected to directly detect the effects of aging." While this discussion pertains to detecting aging-related degradation of active components, it also applies to detecting degradation of the same active components due to aging-related degradation of nonsafety-related components.

Based on the information presented above, the System Walkdown Program is adequate as an aging management program because it includes periodic walkdowns that will detect conditions that could result in failures caused by exposure to spray or wetting regardless of the internal or external environments and their aging effects.

Clarification Requested by the Staff:

The applicant is requested to provide further justification that utilization of the System Walkdown Program, B.1.38, will manage aging effects for all components identified in Table 3.3.2-11 with differing internal and external environments sufficiently to maintain the components intended function and ensure operation of safety related equipment will not be jeopardized during the period of license renewal.

I&M's Supplemental Response to RAI 3.3.2.1.11-1:

As shown in LRA Table 3.3.2-11, in addition to System Walkdown Program, the Water Chemistry Control Program will manage the effects of aging on the components with an internal environment of treated water, except for level glass gauges and molded plastic tanks. Because the glass in the level gauges is inherently resistant to potential aging effects in air, treated water, raw or untreated water, or untreated borated water environments, it has no aging effects requiring management. The molded plastic tanks in the ice condenser system are exposed to an internal treated water environment (i.e., glycol mixture) that is monitored by the Auxiliary Systems Water Chemistry Control Program described in LRA Section B.1.40.3.

Additionally, as indicated in LRA Table 3.3.2-11, the Flow-Accelerated Corrosion Program will also manage the effects of aging on components with an internal steam environment, except for copper heater coils, cast iron strainer housings and carbon steel traps. I&M will include the auxiliary steam system copper heater coils, cast iron strainer housings, and carbon steel traps exposed to an internal steam environment in the Chemistry One-Time Inspection Program, which is described in LRA Section B.1.41.

The remaining components in LRA Table 3.3.2-11 with differing internal and external environments that credit only the System Walkdown Program for aging management are exposed to internal raw or untreated water environments. The following table identifies the fluid-filled mechanical systems that contain these components.

SYSTEM CODE	SYSTEM NAME
CF	Chemical Feed
CONT	Containment
DRAIN	Process Drains
LTW	Lake Township Water
NESW	Non-Essential Service Water
NS	Nuclear Sampling
PASS	Post-Accident Sampling
RMS	Radiation Monitoring
RWD	Radioactive Waste Disposal
SD	Station Drainage

The following discussion provides additional basis for acceptability of other programs for managing the effects of aging on the CF, LTW, NESW, and NS systems that have components containing raw or untreated water.

1. The CF system contains water treated with chemicals to reduce corrosion in the steam generators. This environment was conservatively classified as untreated water although it is actually chemically treated.

2. The LTW system contains water that has been chemically treated by the municipality prior to being used at the site, but was conservatively classified as untreated water in the aging management review. Because LTW chemistry is not controlled by CNP, a chemistry control program was not credited in the LRA. However, as documented in I&M's supplemental response to RAI 3.3.2.1.9-6 in this letter, the extent of aging effects on security diesel system components containing LTW will be confirmed by the Chemistry One-Time Inspection Program, which will inspect a representative sample of 10 CFR 54.4(a)(2) components in the LTW system.

3. The NS system contains heat exchangers exposed to an internal raw water (NESW) environment. The NESW system has the same suction source and is chemically treated in the same manner as the essential service water (ESW) system. The Service Water System Reliability Program will manage the effects of aging on 10 CFR 54.4(a)(2) components containing NESW, because these components are fabricated from the same materials and are exposed to the same environments as components in the ESW system.

The remaining systems (CONT, DRAIN, PASS, RMS, RWD, and SD) have copper alloy, carbon steel, stainless steel, or glass components that may be pressurized and contain raw or untreated water. As discussed previously, glass exposed to raw or untreated water exhibits no aging effects requiring management. I&M will include these 10 CFR 54.4(a)(2) components that are subject to aging management review in the Chemistry One-Time Inspection Program.

Loss of material, if any, from the 10 CFR 54.4(a)(2) components discussed above is expected to progress slowly. The one-time inspection of these components will provide assurance that loss of material is occurring at a rate slow enough to ensure that the intended functions of the components will be maintained during the period of extended operation. This one-time inspection will be performed near the end of the current operating term. The visual inspections will identify indications of loss of material. If loss of material is identified, an evaluation will be performed to confirm that the rate is sufficiently slow that loss of intended function will not occur during the period of extended operation. For material and environment combinations with no evidence of loss of material or with very gradual loss of material, no further actions will be taken. For material and environment combinations with loss of material rates such that loss of intended function could occur during the period of extended operation, corrective actions will be taken in accordance with the Corrective Action Program. Appropriate corrective actions may consist of component replacement or additional inspections for components with the material and environment combination in which the excessive loss of material is found.

RAI 3.3.2.1.11-2:

Table 3.3.2-11, page 3.3-131, identifies the System Walkdown Program, B.1.38, page B-119 of the LRA, as managing loss of material of a stainless steel filter housing in an untreated water with boron internal environment. This is an example of one of several stainless steel components that identify the System Walkdown AMP, B.1.38, as managing loss of material in internal environments. System Walkdown Program, Section B.1.38, page B-119 to B-121, does not credit the program with management of loss of material to stainless steel. Justify utilization of the System Walkdown Program, B.1.38, in managing loss of material to stainless steel components exposed to an untreated water with boron internal environment for each component in Table 3.3.2-1. Also, explain how a system walkdown can inspect and verify proper management of all internal aging effects.

Original I&M Response to RAI 3.3.2.1.11-2:

Management of internal loss of material in stainless steel components was an inadvertent omission from LRA Section B.1.38. This aging effect was included in the aging management review for filter housings in the radioactive waste disposal system cited in this RAI as well as other stainless steel components.

For the 10 CFR 54.4(a)(2) component types in LRA Table 3.3.2-11 that credit the System Walkdown Program, the concern is the impact of spray or leakage from nonsafety-related components onto safety-related equipment. Providing the effect of nonsafety-related component failures on safety-related equipment is managed, safety-related equipment will continue to be capable of performing its required intended functions.

The System Walkdown Program, as described in LRA Section B.1.38, manages aging through visual inspections of systems and components. This program includes periodic walkdowns that will detect and correct failures that could result in long-term exposure to spray or wetting. Short-term exposure is not a concern for passive components such as valve bodies and piping. Active safety-related component failures due to short-term exposure would be detected in the course of normal operation or through monitoring required by the Maintenance Rule and appropriate corrective actions would be taken to prevent recurrence. This is consistent with the NRC's position provided in the Statements of Consideration for the Final Part 54 Rule, which states, "On the basis of consideration of the effectiveness of existing programs which monitor the performance and condition of systems, structures, and components that perform active functions, the Commission concludes that structures and components associated only with active functions can be generically excluded from a license renewal aging management review. Functional degradation resulting from the effects of aging on active functions is more readily determinable, and existing programs and requirements are expected to directly detect the effects of aging." While this discussion pertains to detecting aging-related degradation of active components, it also applies to detecting degradation of the same active components due to aging-related degradation of nonsafety-related components.

Based on the information presented above, the System Walkdown Program is adequate as an aging management program, because it includes periodic walkdowns that will detect conditions that could result in failures caused by exposure to spray or wetting, regardless of the internal or external environments.

Clarification Requested by the Staff:

The applicant is requested to provide further justification that the System Walkdown Program will maintain the intended pressure boundary function for each stainless steel component define in Table 3.3.2-11 with an internal environment of untreated water with boron and an external air environment where the System Walkdown Program, B.1.38, is utilized to manage loss of material aging effect.

I&M's Supplemental Response to RAI 3.3.2.1.11-2:

As indicated in I&M's supplemental response to RAI 3.3.2.1.11-1, the stainless steel components listed in LRA Table 3.3.2-11 with an internal environment of untreated water with boron and an external air environment will be included in the Chemistry One-Time Inspection Program to provide assurance that the pressure boundary function will be maintained through the period of extended operation.

RAI 3.3.2.1.11-3:

LRA Table 3.3.2-11 identifies the System Walkdown Program as managing loss of material, cracking, and change in material properties for the internals of various components such as condenser shell, evaporator housing, filter housing, flex hose, heat exchanger shell, heater coil, heater housing, manifold piping, orifice, piping, pump casing, strainer housing, tank, thermowell, trap, tubing, valve, and ventilation unit housing. The System Walkdown Program performs inspections on accessible surfaces during walkdowns. Explain how the System Walkdown Program will detect loss of material on the internal surfaces of these components.

Original I&M Response to RAI 3.3.2.1.11-3:

The System Walkdown Program, as described in LRA Section B.1.38, manages aging through visual inspections of systems and components. These inspections will detect loss of material on the internal surfaces of these components by observing for evidence of leakage on the external surfaces of the components. For those components where the System Walkdown Program is credited as the aging management program for the internal surfaces, the concern is the impact of spray or leakage from nonsafety-related components on safety-related equipment. By managing the aging effects of nonsafety-related component failures on safety-related equipment, safety-related equipment will continue to be able to perform required intended functions.

The System Walkdown Program, as described in LRA Section B.1.38, manages aging through visual inspections of systems and components. The System Walkdown Program includes periodic walkdowns that will detect and correct failures that could result in long-term exposure to spray or wetting. Short-term exposure is not a concern for passive components such as valve bodies and piping. Active safety-related component failures due to short-term exposure would be detected in the course of normal operation or through monitoring required by the Maintenance Rule and appropriate corrective actions would be taken to prevent recurrence. This is consistent with the NRC's position provided in the Statements of Consideration for the Final Part 54 Rule, which states "On the basis of consideration of the effectiveness of existing programs which monitor the performance and condition of systems, structures, and components that perform active functions, the Commission concludes that structures and components associated only with active functions can be generically excluded from a license renewal aging management review. Functional degradation resulting from the effects of aging on active functions is more readily determinable, and existing programs and requirements are expected to directly detect the effects of aging." While this discussion pertains to detecting aging-related degradation of active components, it also applies to detecting degradation of the same active components due to aging-related degradation of nonsafety-related components.

Based on the information presented above, the System Walkdown Program is adequate as an aging management program for managing loss of material on the internal surfaces of components in LRA Table 3.3.2-11 because it includes periodic walkdowns that will detect and correct conditions that could result in failures caused by exposure to spray or wetting.

Clarification Requested by the Staff:

The applicant is requested to provide further justification that the System Walkdown Program will maintain the specified functions for the internals of various components such as condenser shell, evaporator housing, filter housing, flex hose, heat exchanger shell, heater coil, heater housing, manifold piping, orifice, piping, pump casing, strainer housing, tanks, thermowell, traps, tubing, valves, and ventilation unit housings listed in Table 3.3.2-11 where the System Walkdown Program, B.1.38, is utilized to manage the aging effects loss of material, cracking, and change in material properties.

I&M's Supplemental Response to RAI 3.3.2.1.11-3:

See I&M's supplemental response to RAI 3.3.2.1.11-1.

Bolting and Torquing – Aging Management Review and Programs

RAI 3.2-5:

LRA Table 3.2.2-2 credits the Bolting and Torquing Activities programs for managing the loss of mechanical closure integrity of carbon steel and stainless steel bolts in an external air environment. The applicant is requested to discuss how cracking and loss of preload resulting in loss of mechanical closure integrity is managed. Also the applicant is requested to provide the inspection activities in its program which are equivalent to the appropriate ASME Section XI requirements. In addition the applicant is requested to address how the aging effects are managed for inaccessible bolts. These include bolts such as those located in cavities or obstructed by other components and devices.

Original I&M Response to RAI 3.2-5:

Cracking: SCC occurs through the combination of high stress, a corrosive environment, and a susceptible material (such as that used in high-strength bolts). CNP piping material specifications do not permit, nor have they historically permitted, high-strength bolting in non-Class 1 systems. Proper lubricants and sealant compounds are used to minimize the potential for SCC. In the aging management reviews, sufficient stress to initiate SCC was assumed if bolting was subject to a corrosive environment. Since bolted closures do not contain high-strength bolting, are not submerged or exposed to lubricants containing contaminants, and are exposed to ambient temperature rather than high-temperature process fluids, cracking is not an aging effect requiring management for non-Class 1 closure bolting in an external air environment.

Review of operating experience did not identify problems with cracking of carbon or stainless steel bolting in air environments.

Loss of Pre-load: The Bolting and Torquing Activities Program assures that proper torque values are applied to bolted closures such that loss of mechanical closure integrity as a result of loss of pre-load does not occur.

ASME Code Applicability: The Bolting and Torquing Activities Program, Boric Acid Corrosion Prevention Program, and System Walkdown Program manage loss of mechanical closure integrity for closure bolting as described in LRA Sections B.1.2, B.1.4, and B.1.38, respectively. Visual inspections of bolting for loss of material and loss of mechanical closure integrity in the Boric Acid Corrosion Prevention Program and System Walkdown Program are adequate to assure that the closure bolting can perform its intended function since loss of material (and ultimately loss of mechanical closure integrity) for external surfaces such as closure bolting is a long-term aging effect that would be observed well before aging progressed to the point of loss of intended function. The Bolting and Torquing Activities Program assures that proper torque values are applied to bolted closures such that loss of mechanical closure integrity as a result of loss of preload due to high temperatures does not occur.

The Bolting and Torquing Activities program is a plant-specific program and is not comparable to NUREG-1801, Section XI.M18, "Bolting Integrity," which stipulates the inspection requirements of ASME Code, Section XI. These requirements are included in the Inservice Inspection Program for Class 1, 2, and 3 bolted closures. However, these inspection requirements are focused on identifying the aging effect of cracking. Since cracking is not an aging effect requiring management for non-Class 1 bolted closures, the Inservice Inspection Program is not an applicable aging management program for these components.

Inaccessible Bolting Aging Management: When bolted closures are assembled, proper bolting material and appropriate lubricants and sealants are selected in accordance with EPRI NP-5067, *Good Bolting Practices.* Torque values are monitored when the bolted closure is assembled. Maintenance personnel visually inspect components used in bolted closures to assess their general condition during maintenance. Gaskets, gasket seating surfaces, and fasteners are inspected for damage that would prevent proper sealing. Therefore, the Bolting and Torquing Activities Program manages aging effects for bolting, whether accessible or inaccessible. The Bolting and Torquing Activities Program applies to bolting both inside and outside of containment.

Clarification Requested by the Staff:

The applicant's discussion of cracking is limited to stress corrosion cracking. GALL (VIII H.2-b) also discusses cracking in closure bolting in high pressure or high temperature systems due to cyclic loading. The potential for cracking caused by cyclic loading should also be included in the discussion.

In the response related to ASME Code applicability, the applicant stated that the Bolting and Torquing Activities Program assures that proper torque values are applied to bolted closures such that the loss of mechanical closure integrity as a result of loss of preload due to high temperature does not occur. GALL AMP XI.M18 encompasses all safety related bolting. If AMP B.1.2, Bolting and Torquing Activities Program, is limited to only high temperature bolting and applications subject to significant vibration, the applicant is requested to clarify how loss of preload is prevented in other safety related bolting.

[Note: Prior to submittal of this response, I&M discussed the proposed response with the Staff, to ensure the questions were understood. The following additional clarifications were requested in response to those discussions.]

The supplemental response to RAI 3.2-5 identifies that cracking of bolting due to cyclic loading is not an aging effect requiring management for non-Class 1 bolting applications due to low operating temperatures. This position is inconsistent with the GALL Bolting Integrity

AMP XI.M18 and GALL non-Class 1 bolting items V E.2-b, VII I.2-b, VIII H.2-b, which specifically identify crack initiation due to cyclic loading in non-Class 1 closure bolting. Since the LRA does not include a bolting integrity program consistent with GALL XI.M18, the applicant is requested to clarify how crack initiation and growth caused by cyclic loading is managed in non-Class 1 bolting.

The supplemental response to RAI 3.2-5 identifies that loss of preload is an aging effect requiring management only for bolting subject to elevated temperatures or significant vibration. This position is inconsistent with the GALL bolting integrity AMP XI.M18 and its bases. GALL AMP XI.M18 identifies loss of preload as an aging effect and this document specifically includes bolting preload control and periodic inspection of closure bolting for loss of preload. EPRI NP-5769 referenced in GALL XI.M18 states that, "preload reduction is caused by a number of factors, including stress relaxation (both at room temperature and elevated temperature), thermal cycling (particularly for gaskets), creep and flow of gasket material during initial compression, vibration and shock, and elastic interactions between separately tightened bolts." In addition, the scope of the program described in GALL XI.M18 encompasses all safety related bolting. The applicant is requested to clarify the temperature at which loss of preload is not considered an aging effect and the technical justification, including the basis, that loss of preload is not applicable to such closure bolting.

I&M's Supplemental Response to RAI 3.2-5:

[Note: This supplemental response responds to the NRC Staff's initial clarification request and follow-on clarification requested prior to submittal of the I&M clarification.]

NUREG-1801, Section XI.M18, "Bolting Integrity," notes that industry operating experience has identified occurrences of cyclic loading-induced degradation of threaded fasteners in reactor coolant pressure boundary (Class 1) closures (NRC Bulletin 82-02 and NRC Generic Letter 91-17). As indicated in the aging management review results tables in LRA Section 3.1, this aging effect is managed by the Inservice Inspection Program. NUREG-1801, Section XI.M18, does not identify crack initiation due to cyclic loading as an aging effect applicable to non-Class 1 closure bolting. NUREG-1801 non-Class 1 bolting items V E.2-b, VII I.2-b, and VIII H.2-b identify crack initiation and growth due to cyclic loading and due to SCC as aging effects applicable to non-Class 1 closure bolting in high-pressure or high-temperature systems.

As noted in the original I&M response to RAI 3.2-5, bolted closures at CNP do not contain high-strength bolting, are not submerged or exposed to lubricants containing contaminants, and are exposed to ambient temperature rather than high-temperature process fluids. Therefore, cracking due to stress corrosion is not an aging effect requiring management for non-Class 1 closure bolting in an external air environment. Correspondingly, as described in EPRI 1003056, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 3," Appendix F, crack initiation and growth due to cyclic loading is not an aging effect requiring management for non-Class 1 bolting applications because the operating temperatures are lower than those for the Class 1 bolting applications. A review of recent industry and plant operating experience did not identify problems with cracking of non-Class 1 carbon or stainless steel bolting in air environments.

The NUREG-1801 Bolting Integrity Program is a comprehensive program to manage bolted closure integrity. It addresses loss of material, cracking, and loss of preload for all bolted closures within the scope of license renewal, including safety-related bolting, bolting for nuclear steam supply system (NSSS) component supports, bolting for other pressure-retaining components, and structural bolting. The CNP Bolting and Torquing Activities Program addresses only loss of preload for bolting subjected to elevated temperatures or significant vibration, such as that due to diesel engine operation. This aging effect was conservatively assumed to be applicable to bolting in systems with temperatures above 400°F, which is below the 700°F elevated temperature threshold for this aging effect accepted in NUREG-1787, *Safety Evaluation Report Related to the License Renewal of the Virgil C. Summer Nuclear Station* [ML040300170].

Other aspects of the NUREG-1801, Section XI.M18, are addressed by other CNP programs. For example, the ASME Section XI requirements are included in the CNP Inservice Inspection Program for Class 1, 2, and 3 bolted closures. Also, the Boric Acid Corrosion Prevention Program and System Walkdown Program include periodic inspections of pressure-retaining components (including the closure bolting) for signs of leakage that may be due to loss of preload, cracking, or loss of material.

RAI B.1.2.2-1:

Program Scope: The applicant stated that the Bolting and Torquing Activities Program covers bolting in high temperature systems and in applications subject to significant vibration, as identified in the aging management reviews.

The Program Scope did not identify the applicable AMP's that are credited with managing age related degradation of bolting or threaded fasteners.

The staff requests the applicant to identify the AMP's that are credited with managing age related degradation of bolting and/or threaded fasteners and identify the material and the systems they are in.

Original I&M Response to RAI B.1.2.2-1:

Aging management reviews of the following systems credit the Bolting and Torquing Activities Program with managing loss of mechanical closure integrity for carbon and stainless steel bolting:

Exposed to High Temperatures or Vibration from Diesel Engines

System	LRA Section	LRA Table
Fire protection (fire pump diesel engine)	3.3.2.1.7	3.3.2-7
Emergency diesel engine	3.3.2.1.8	3.3.2-8
Security diesel engine	3.3.2.1.9	3.3.2-9

Exposed to High Temperatures

System	LRA Section	LRA Table
Containment isolation	3.2.2.1.2	3.2.2-2
Miscellaneous systems in scope for 10 CFR 54.4(a)(2)	3.3.2.1.11	3.3.2-11
Main feedwater	3.4.2.1.1	3.4.2-1
Main steam	3.4.2.1.2	3.4.2-2
Auxiliary feedwater	3.4.2.1.3	3.4.2-3
Steam generator blowdown	3.4.2.1.4	3.4.2-4

The aging management review of the RCS credits the Bolting and Torquing Activities Program, in conjunction with the Inservice Inspection Program and the Boric Acid Corrosion Prevention Program, with managing loss of mechanical closure integrity for:

- low alloy steel and stainless steel bolting for Class 1 valves and blind flanges, as listed in LRA Table 3.1.2-3;
- low alloy steel bolting for reactor coolant pump main flange and pressurizer manway bolting, as listed in LRA Tables 3.1.2-3 and 3.1.2-4; and
- low alloy steel and carbon steel bolting for steam generator components, as listed in LRA Table 3.1.2-5.

Clarification Requested by the Staff:

The RAI response does not clarify why the scope does not include all safety related bolting as addressed in GALL AMP XI.M18.

I&M's Supplemental Response to RAI B.1.2.2-1:

NUREG-1801, Section XI.M18, "Bolting Integrity," is a comprehensive program to manage bolted closure integrity. It addresses loss of material, cracking and loss of preload for all bolted closures within the scope of license renewal including safety-related bolting, bolting for NSSS component supports, bolting for other pressure-retaining components, and structural bolting. The Bolting and Torquing Activities Program credited in LRA Section B.1.2 addresses only loss of preload for in-scope bolting subjected to elevated temperatures and/or significant vibration, such as that due to diesel engine operation.

Other aspects of the program described in NUREG-1801, Section XI.M18, are addressed by other CNP programs. For example, the ASME Section XI requirements for Class 1, 2, and 3 bolted closures are included in the CNP Inservice Inspection Program. Since cracking is not an aging effect requiring management for non-Class 1 bolted closures, the Inservice Inspection Program is not an applicable aging management program for these components. The Boric Acid Corrosion Prevention Program and System Walkdown Program include periodic visual inspections of pressure-retaining components (including closure bolting) for signs of leakage that may be due to loss of material, cracking, or loss of mechanical closure integrity (loss of preload). The Structures Monitoring Program provides the requirements for inspection of structural and component support bolting within the scope of license renewal that is not monitored by the Inservice Inspection Program. The Structures Monitoring – Ice Basket Inspection Program monitors ice basket bolting. The Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program and the Inservice Inspection Program provide the requirements for the inspection of bolting internal to the reactor vessels.

In summary, the aspects of the program described in NUREG-1801, Section XI.M18, are addressed by CNP programs such as the Bolting and Torquing Activities; Inservice Inspection; Boric Acid Corrosion Prevention; System Walkdown; Structures Monitoring; Structures Monitoring – Ice Basket Inspection; and Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Programs. All safety-related bolting addressed in NUREG-1801, Section XI.M18, is monitored by one or more of these programs commensurate with the appropriate aging effect. LRA Section 3 identifies the aging effects for bolting and the programs that manage the applicable aging effects.

RAI B.1.2.2-2:

Preventive Actions: The applicant stated that the Preventive Actions include proper selection of bolting material and use of appropriate lubricants and sealants in accordance with Electric Power Research Institute (EPRI) guidelines. The applicant stated that the initial inspection of bolting for pressure-retaining components includes a check of the bolt torque and uniformity of the gasket compression after assembly. Hot torque checks are not applied to all bolted closures within the scope of this program, but are controlled procedurally if it is a vendor-recommended action or if it is determined that hot torque is necessary on a case-by-case basis.

The Preventive Actions did not clearly indicate what EPRI guidelines would be utilized to select proper bolting material, lubricants and sealants. The applicant did not identify what actions and materials would be used for replacement to demonstrate acceptable management of ARDMs.

The staff requests the applicant to identify the EPRI guidelines to be used for selection of bolting materials lubricants and sealants, including specific actions and material replacements to demonstrate acceptable management of ARDMs. Also, provide an example of a case by case basis that would require a hot torque check of a bolted closure.

I&M Response to RAI B.1.2.2-2:

The EPRI guidelines used are NP-5067, *Good Bolting Practices,* and TR-104213, *Bolted Joint Maintenance & Applications Guide.*

Fastener material replacements are performed in accordance with piping specifications or approved configuration changes. Piping specifications require that boric acid corrosion resistant fastener material be used for bolted joints on systems containing borated water. Also, low yield strength bolting and low chloride and sulfur content threaded fastener lubricants are specified to minimize the potential for SCC.

The site maintenance procedure for the feedwater stop check valves provides an example of hot torque requirements. The procedure requires re-torquing of the bonnet cap screws at normal operating temperature and pressure as a final post-maintenance condition, as recommended by the vendor technical manual.

Clarification requested for RAI B.1.2.2-2:

The RAI response identifies appropriate EPRI references, but does not address the exceptions identified in NUREG-1339 referenced in GALL AMP XI.M18. Compliance with NUREG-1339 to resolve GSI-29 may be more of an operating issue for compliance with GL 91-17 rather than an aging issue.

I&M's Supplemental Response to RAI B.1.2.2-2:

NUREG-1339, Section 3, states in part that "The NRC staff found technical disagreement with several specific discussions in EPRI NP-5769 . . ." and continues with a discussion of five areas of disagreement. The areas that have license renewal implications are summarized below with I&M's response.

(1) The first area pertains to the use of experimentally verified (rather than assumed) fastener material properties and fracture mechanics analyses to ensure that safety-related fasteners are unlikely to be susceptible to stress-corrosion cracking.

CNP purchase order specifications for safety-related bolting specify the applicable ASME/ASTM material specifications. A review of certified material test reports (CMTRs) received with safety-related bolting material shipments confirmed that material properties (e.g., tensile strength, hardness, yield strength, proof strength) are experimentally verified by mechanical testing methods. If a discrepancy between the material specification and the CMTR is identified upon receipt inspection, a discrepancy report is initiated and evaluated, prior to issuing the material for use in the plant.

(2) The second area pertains to categorization of bolting steels based only on the actual measured yield strength (S_y) of the material (or S_y determined by conversion of measured hardness values) and not on the specified minimum yield strength. This discussion characterized high-strength bolts as those with $S_y \geq 150$ ksi and medium-strength bolts as those with S_y between 120 ksi and 150 ksi.

In the referenced June 30, 2004, letter, I&M's response to RAI 3.2-5 indicated that CNP piping material specifications do not permit, nor have they historically permitted, high-strength bolting in non-Class 1 systems. A review of a sample population of CMTRs, for bolting, including structural, non-Class 1 and Class 1 bolting, did not reveal yield strengths greater than 141 ksi. As discussed in paragraph (1) above, actual measured yield strength and other mechanical test data was reported on CMTRs.

(3) The third area pertains to the accuracy of data in EPRI NP-5769, Tables 2-1 and 11A-1.

I&M does not use these tables to convert hardness data to tensile strengths for bolting. A review of a sample population of CMTRs for bolting confirmed that the actual tensile strengths are provided by the vendor in the CMTRs, along with other test data.

(4) The fourth area pertains to the use of molybdenum disulfide (MoS_2) as a lubricant.

During the mid-1980s, Westinghouse NSSSs experienced significant thread galling and fastener damage upon removal of primary and secondary closures. This resulted in Westinghouse issuing Technical Bulletin 87-01 "Steam Generator Closures and Primary Manway Installation and Removal Recommendations." This bulletin discussed methods and equipment recommendations designed to minimize the potential for seized fasteners and leakage on steam generator and pressurizer closures. These recommendations included a change in thread lubricant, which was subsequently incorporated into site procedures for steam generator and pressurizer manway cover removal and installation. I&M does not use MoS_2 as a lubricant on studs for the steam generator and pressurizer manway covers. In addition, procedural controls are in place to ensure that I&M does not use MoS_2 as a lubricant on stainless steel bolting in the CNP Unit 1 or Unit 2 primary or secondary systems.

(5) The fifth area pertains to specified use of a more recent reference in fracture mechanics analyses and is not a license renewal concern.

Reference for Supplemental Response to RAI B.1.2.2-2

Letter from M. K. Nazar, I&M, to NRC Document Control Desk, "Donald C. Cook Nuclear Plant, Units 1 and 2, License Renewal Application - Response to Requests for Additional Information on Engineered Safety Features, Auxiliary Systems, and Steam and Power Conversion Systems (TAC Nos. MC1202 and MC1203)," AEP:NRC:4034-09, dated June 30, 2004 [Accession No. ML041890378].

RAI B.1.2.2-4:

Detection of Aging Effects: The applicant stated that the Detection of Aging Effects is a preventive program. The applicant stated that actions performed under the program prevent the aging effect of loss of mechanical closure integrity. The applicant stated this program is credited with managing the loss of mechanical closure integrity for bolted connections and bolted closures.

The applicant stated that the intent of this element was to manage the loss of mechanical closure integrity for bolted connections and bolted closures. However, the applicant did not provide justification to support the program's ability to accomplish this.

The staff requests the applicant to provide justification, including codes and standards referenced that the technique and frequency used at CNP are adequate to detect the aging effects before a loss of component function occurs.

Original I&M Response to RAI B.1.2.2-4:

The Bolting and Torquing Activities Program manages loss of mechanical closure integrity due to loss of preload for closure bolting in high-temperature systems and applications subject to significant vibration. Specific applications are identified in the LRA Section 3 aging management review results tables.

Program standards are EPRI NP-5067, *Good Bolting Practices*, and TR-104213, *Bolted Joint Maintenance & Applications Guide*. These standards are used throughout the industry and have proven effective in managing loss of preload for closure bolting. Review of operating experience did not identify problems with loss of preload for bolted closures at CNP.

Clarification Requested by the Staff:

The applicant response states that a review of operating experience did not identify problems with loss of preload for bolted closures at CNP. The applicant should be requested to clarify if the absence of problems is consistent with industry experience and if the absence of problems implies that no leakage has resulted due to loss of preload.

I&M's Supplemental Response to RAI B.1.2.2-4:

Review of recent industry and plant operating experience did not identify problems with loss of preload for bolted closures. As stated in the original I&M response to RAI B.1.2.2-4, CNP program standards are EPRI NP-5067, "Good Bolting Practices" and TR-104213, "Bolted Joint Maintenance & Applications Guide." These standards are used throughout the industry and have proven effective in managing loss of preload for closure bolting.

The absence of recent problems does not imply that no leakage has resulted from loss of preload. However, the frequency of leakage has decreased following adoption of the above industry standards. When minor leakage has occurred, it has been identified and corrected, promptly restoring the pressure boundary intended function of the component. Significant or repetitive leakage would lead to prompt corrective actions through the Corrective Action Program.

Electrical Systems – Scoping and Aging Management Review

RAI 2.5-1:

Interim Staff Guidance (ISG) 2, "NRC Staff Position on the License Renewal Rule (10 CFR 54.4) as it relates to The Station Blackout Rule (SBO) (10 CFR 50.63)," states, in part, that "The offsite power systems consist of a transmission system (grid) component that provides a source of power and a plant system component that connects that power source to a plant's onsite electrical distribution system which power safety equipment." For the purpose of the license renewal rule, the staff determined that the plant system portion of the offsite power system that is used to connect the plant to the offsite power source should be included within the scope of the rule. This path typically includes the switchyard circuit breakers that connect to the offsite system power transformers (startup transformer), transformers themselves, the intervening overhead or underground circuits between circuit breaker and transformer and transformer and onsite electrical distribution system, and the associated control circuits and structures. In this regard, the portion of the SBO path indicated on the offsite power boundary drawing for license renewal does not include the transmission conductors and connections and the associated control cables from the first breaker (disconnect) from the 345 kV [kilovolt] and 765 kV switchyard buses to the 765 kV/34.5 kV and 345 kV/34.5 kV transformers. Please revise this drawing to include the above components indicating which components require an aging management review (AMR).

Clarification Requested by the Staff:

Confirm that the portion of the cables which are not routed underground will be managed by the GALL XI.E1 program.

I&M's Supplemental Response to RAI 2.5-1:

As stated in I&M's response to RAI 2.5-1 in the referenced June 8, 2004, letter, the portion of the SBO path indicated on the license renewal offsite power boundary drawing, 12-LRA-Electrical1, includes the switchyard circuit breakers that connect to the offsite system power transformers (startup transformers), the transformers themselves, and the intervening overhead or underground circuits between circuit breakers and transformers and between transformers and the onsite electrical distribution system. The 4.16 kV insulated cables installed between the Unit 1 reserve auxiliary transformers, also referred to as startup transformers or offsite system power transformers, TR101AB and TR101CD, and the plant safety busses are routed above ground. These insulated cables, which are part of the 4KVAC system, will be included in the Non-EQ Insulated Cables and Connections Program. As discussed in LRA Section B.1.22, this program will be consistent with the program discussed in NUREG 1801, Section XI.E1, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements. The inaccessible insulated cables installed between the Unit 1 reserve auxiliary transformers and the switchyard circuit breakers and those installed between the

Unit 2 4.16 kV plant safety busses and the switchyard circuit breakers will be included in the Non-EQ Inaccessible Medium-Voltage Cable Program, which will be consistent with the program discussed in NUREG-1801, Section XI.E3, Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements, as discussed in LRA Section B.1.20.

Reference for Supplemental Response to RAI 2.5-1

Letter from M. K. Nazar, I&M, to NRC Document Control Desk, "Donald C. Cook Nuclear Plant, Units 1 and 2, Docket Nos. 50-315 and 50-316, License Renewal Application - Response to Requests for Additional Information on Electrical and Auxiliary Systems," AEP:NRC:4034-06, dated June 8, 2004 [Accession No. ML041680255].

RAI 3.6-1:

In response to audit team's question on fuse holders, you stated that you have completed an assessment to identify fuse holders that are subject to AMR based on requirements of license renewal and Interim Staff Guidance (ISG)-5, "Identification and Treatment of Electrical Fuse Holders For License Renewal." The assessment identified fuse holders in scope for license renewal, then screened in fuse holders in-scope based upon whether: (1) they are included in an active component (panels, switchgear, or cabinet), (2) they perform an intended function to meet the criteria of 10 CFR 54.4 (a) (i.e., isolate safety loads from non-safety loads or are used as protective devises to ensure the integrity of containment electrical penetrations), or (3) they have bolted connections, which are not subject to the same aging stressors (i.e., mechanical stress and fatigue) as spring loaded fuse holder clips. The assessment determined that fuse blocks are either an active components, do not perform a license renewal intended function, or have bolted connections. With regard to the fuse holders that have bolted connections, please address the aging affects due to vibration, corrosion, and fatigue due to thermal cycling identified in the subject ISG and provide justification as to why an additional AMP for bolted connection fuse holders is not required.

Original I&M Response to RAI 3.6-1:

The CNP aging management review of electrical systems eliminated fuses with bolted connections, since bolted connections do not have the issue associated with metallic fuse clamps. Bolted connections on fuse holders are subject to the same aging effects as bolted connections included in the cables and connections commodity group. The CNP aging management review included bolted connections on fuse holders as connections in the cable and connections commodity group.

All of the fuse holders that were not part of an active component and that were screened solely on the bolted connection criterion have the system code "26KAC" (electrical distribution system, 26,000 VAC). The 26KAC system is within the scope of license renewal, based on the bounding approach used for scoping electrical systems, and is listed in LRA Table 2.2-1b. This system contains the components associated with the 26 kV bus, which is the electrical distribution associated with the main generator. The main generator and step-up transformers do not perform a license renewal intended function; therefore, these fuse holders were determined not to be subject to an aging management review.

Clarification Requested by the Staff:

With regard to RAI 3.6-1, the applicant states that the bolted connection on fuse holders are subject to the same aging effects as bolted connections included in the cable and that the bolted connection program will be managed by the cable and connection program. However, it is not clear if this program will include aging effects that are included in the RAI. Also, aging effects of connections are not described in the XI.E1 program. Please provide this information.

I&M's Supplemental Response to RAI 3.6-1:

As stated in Appendix E of Nuclear Energy Institute (NEI) 95-10, *Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – the License Renewal Rule*, Revision 4, fuse holders are considered to be passive commodities similar to terminal blocks. ISG-5 provided additional guidance for aging effects associated with fuse holders that use metallic clamps to hold the fuse. Plant-specific Note 1 was added to LRA Table 3.6.2-1 for the component type "Electrical cables and connections not subject to 10 CFR 50.49 EQ requirements" stating, "The aging management program does not include the metallic fuse clamp portion of fuse holders. The metallic fuse clamp portion of fuse holders that are in scope for ISG-5 will be evaluated prior to the end of the current license term." Subsequent to LRA submittal, the evaluation for ISG-5 scope was completed and determined that no fuse holders at CNP meet the ISG-5 criteria requiring aging management. As stated in the NRC Staff's original question in RAI 3.6-1, the CNP fuse holders were screened based on three criteria: (1) they are included in an active component (panels, switchgear, or cabinet), (2) they perform no intended function to meet the criteria of 10 CFR 54.4(a) (i.e., isolate safety loads from non-safety loads or are used as protective devices to ensure the integrity of containment electrical penetrations), or (3) they have bolted connections, which are not subject to the aging stressors (i.e., mechanical stress and fatigue) for spring loaded fuse holder clips.

After receiving the clarification requested for RAI 3.6-1, I&M again reviewed the fuse holders that were eliminated solely based on having bolted connections instead of metallic spring clamps. As stated in I&M's response to RAI 3.6-1 in the referenced June 8, 2004, letter, "All of the fuse holders that were not part of an active component and that were screened solely on the bolted connection criterion have the system code "26KAC" (electrical distribution system, 26,000 VAC) ... This system contains the components associated with the 26 KV bus, which is the electrical distribution associated with the main generator. The main generator and step-up transformers do not perform a license renewal intended function; therefore, these fuse holders [with bolted connections] were determined not to be subject to an aging management review." Based on this information, no bolted fuse holders perform a license renewal intended function, are subject to aging management review, or are included in the Non-EQ Cables and Connections Program for the ISG-5 criteria.

Reference for Supplemental Response to RAI 3.6-1

Letter from M. K. Nazar, I&M, to NRC Document Control Desk, "Donald C. Cook Nuclear Plant, Units 1 and 2, Docket Nos. 50-315 and 50-316, License Renewal Application - Response to Requests for Additional Information on Electrical and Auxiliary Systems," AEP:NRC:4034-06, dated June 8, 2004 [Accession No. ML041680255].

RAI 3.6-2:

With regard to non-EQ cables sensitive to a reduction in insulation resistence, please confirm consistency with the proposed ISG-15, Revision of Generic Aging Lessons Learned (GALL) Aging management Program (AMP) XI.E2,"Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits."

Original I&M Response to RAI 3.6-2:

The exception to NUREG-1801, Section XI.E2, in LRA Appendix B, Section B.1.21, states, "...the first reviews will be performed before the period of extended operation and every 10 years thereafter. Calibrations or surveillances that fail to meet the acceptance criteria will be reviewed at the time of the calibration or surveillance." The intent of this exception is in agreement with the mark-up of ISG-15 provided to the NRC in the referenced NEI letter dated December 15, 2003 (referenced below). The NRC has not yet issued a formal response to these industry comments. Therefore, it is the intent of this program to be consistent with NUREG-1801, Section XI.E2 with the stated exception, which is consistent with the draft of ISG-15 provided in the referenced NEI letter. Other elements of the Non-EQ Instrumentation Circuits Test Review Program are consistent with ISG-15.

Clarification Requested by the Staff:

Are there any instrumentation cables that are disconnected for the purpose of instrument calibration?

I&M's Supplemental Response to RAI 3.6-2:

CNP has instrumentation cables within the scope of the Non-EQ Instrumentation Circuits Test Review Program that are disconnected during calibration. The current method for detecting deterioration of the insulation on instrumentation cables uses time-domain reflectometry (TDR).

A proven cable test, such as TDR, will be conducted during the period of extended operation as part of the Non-EQ Instrumentation Circuits Test Review Program. The test frequency of instrumentation cables that are in the scope of this program, but are disconnected during calibration, shall be determined by I&M based on engineering evaluation, but will not be less than once per ten years. The NRC Staff issued ISG-15 on August 12, 2003 [Accession No. ML032250579]; the final comments from NEI to the NRC Staff were issued on December 15, 2003 [Accession No. ML033560253]. The test method selected by I&M is consistent with the proposed ISG-15 revision issued on August 12, 2003, NEI comments provided in the December 15, 2003, letter and the previously approved NRC Staff position documented in NUREG-1785, *License Renewal Safety Evaluation Report for the H. B. Robinson Steam Electric Plant, Unit 2* [Accession No. ML040200981]. NUREG-1785, Section 3.6.2.3.2.2, discusses performing testing every 10 years for sensitive instrumentation circuits that are disconnected during calibration and are not part of the calibration program. The NRC Staff found testing acceptable because such testing would determine potential cable degradation, and the 10-year frequency was determined to be acceptable because cable insulation degradation is a slow process, plant-specific operating experience did not identify previous cable degradation, and this frequency is consistent with the NUREG-1801 cable aging management programs. A review of CNP operating experience found no age-related failures for the high-range radiation or the neutron monitoring cables. The only industry operating experience identified for these cables was Westinghouse Technical Bulletin 86-01, which was not applicable to CNP, because the cable insulation material at CNP is different than that discussed in the bulletin. This plant operating experience demonstrates that these cables have operated over long periods without a loss of intended function. Therefore, the Non-EQ Instrumentation Circuits Test Review Program, which will include testing of instrumentation cables that are disconnected during calibration, will provide adequate management of the aging effects for instrumentation cables.

As a result of these changes to include testing of instrumentation cables that are disconnected during calibration, the Non-EQ Instrumentation Circuits Test Review Program description for the UFSAR is revised as follows [New text is shown in *italics*.]:

A.2.1.24 NON-EQ INSTRUMENTATION CIRCUITS TEST REVIEW PROGRAM

The Non-EQ Instrumentation Circuits Test Review Program will manage aging effects for electrical cables that:

1. Are not subject to the environmental qualification requirements of 10 CFR 50.49, and
2. Are used in instrumentation circuits with sensitive, high-voltage, low-level signals exposed to adverse localized environments caused by heat, radiation, or moisture.

An adverse localized environment is defined as being significantly more severe than the specified service environment for the cable. This program will detect aging effects by reviewing calibration or surveillance results for components within the program scope. *A proven cable test for detecting insulation deterioration on in-scope* *instrumentation cables that are disconnected during calibration will be performed at a frequency determined by engineering evaluation, but will not be less than once per ten years.* The Non-EQ Instrumentation Circuits Test Review Program will be implemented prior to the period of extended operation.

RAI 3.6-3:

In response to an audit team's question on inaccessible medium voltage cables within the scope of license renewal that are exposed to significant moisture simultaneously with applied voltage, it was stated that the AMP for inaccessible medium voltage cables will test the cables as well as inspect for water in the manholes. It was also stated that inspection of water in the manholes associated the GALL XI.E3 AMP would be performed every 10 years. The frequency to inspect for water in manholes every ten years may be too long. Justify the frequency of inspecting manholes for water every 10 years in addition, provide your current criteria for inspecting manholes for water.

Original I&M Response to RAI 3.6-3:

LRA Section B.1.20 states that the CNP Non-EQ Inaccessible Medium-Voltage Cable program will be consistent with NUREG-1801, Section XI.E3. NUREG-1801, Section XI.E3, Section 2, "Preventive Actions," states that, "Periodic actions are taken to prevent cables from being exposed to significant moisture, such as inspecting for water collection in cable manholes and conduit, and draining water, as needed. Medium-voltage cables for which such actions are taken are not required to be tested since operating experience indicates that prolonged exposure to moisture and voltage are required to induce this aging mechanism." This section implies that if periodic actions are not taken to prevent cable exposure to significant moisture, then testing is required. The Non-EQ Inaccessible Medium-Voltage Cable Program will require testing of all cables included in the program. The frequency of inspections for water is relevant only if it provides reasonable assurance that the cables are not exposed to significant moisture and therefore do not require testing. Since testing is to be performed regardless of inspection results, the inspection frequency is not relevant. The proposed testing frequency in the CNP aging management program is consistent with NUREG-1801, Section XI.E3, for cables that are exposed to significant moisture.

Clarification Requested by the Staff:

In response to an audit team's question on inaccessible medium voltage cables within the scope of license renewal that are exposed to significant moisture simultaneously with applied voltage, it was stated that the Aging Management Program (AMP) for inaccessible medium voltage cables will test the cables as well as inspected for water in the manholes. It was also stated that the inspection of water in the manholes associated with the Generic Aging Lessons Learned (GALL) XI.E3 AMP would be performed every 10 years. The frequency to inspect for water in *manholes every 10 years may be too long. Justify the frequency of inspecting manholes for water every 10 years. In addition, provide your current criteria for inspecting manholes for water. If you do not inspect for water in the manholes at all, verify how you assure that the cables are not submerged in water for an extended period of time?*

I&M's Supplemental Response to RAI 3.6-3:

LRA Section B.1.20, states that the Non-EQ Inaccessible Medium-Voltage Cable Program will be consistent with NUREG-1801, Section XI.E3. NUREG-1801, Section XI.E3, Section 2, *Preventive Actions*, states, "Periodic actions are taken to prevent cables from being exposed to significant moisture, such as inspecting for water collection in cable manholes and conduit, and draining water, as needed. Medium-voltage cables for which such actions are taken are not required to be tested since operating experience indicates that prolonged exposure to moisture and voltage are required to induce this aging mechanism." This indicates that if actions are taken to prevent cable exposure to significant moisture, then cable testing is not required. However, the Non-EQ Inaccessible Medium-Voltage Cable Program will require testing of all cables in the scope of this program. The frequency of manhole inspections for water is relevant only if it provides reasonable assurance that the cables are not exposed to significant moisture and thus do not require cable testing. Since all cables in the scope of this program will be tested regardless of manhole inspection results, neither the manhole inspection frequency nor the manhole inspection criteria are relevant for license renewal.

The proposed 10-year cable testing frequency in the CNP Non-EQ Inaccessible Medium-Voltage Cable Program is consistent with NUREG-1801, Section XI.E3, for medium-voltage cables that are exposed to significant moisture. NUREG-1801, Section XI.E3 does not provide the basis for the 10-year testing frequency; however, this frequency appears appropriate based on industry guidance and previously approved aging management programs. SAND96-0344, *Aging Management Guidelines for Commercial Nuclear Power Plants – Electrical Cable and Terminations,* which is referenced in NUREG-1801, Section XI.E3, identifies water treeing as the aging mechanism that produces the reduced insulation resistance aging effect. In accordance with SAND96-0344, water treeing is a long-term failure phenomenon for medium-voltage cables due to the relatively slow rate of water tree propagation.

CNP does not have plant-specific operating experience involving failures of medium-voltage underground insulated cables. Although not required by regulations or CNP's current licensing basis, I&M has performed manhole inspections at CNP. During the conduct of these inspections in July 2004, occurrences of submerged medium-voltage cables were identified. Consistent with NUREG-1801, Section XI.E3, cable testing as specified in the Non-EQ Inaccessible Medium-Voltage Cable Program is appropriate for these submerged medium-voltage cables.

Based on industry guidance and operating experience, water tree formation is a slow process that must occur over several years prior to cable failure. Because the Non-EQ Inaccessible Medium-Voltage Cable Program will include testing of all applicable cables prior to entering the period of extended operation, and every 10 years thereafter, the aging effects for these cables will be adequately managed during the period of extended operation.

Other Time-Limited Aging Analyses

RAI 4.3.1-1:

Section 4.3.1 of the LRA discusses the fatigue evaluation of the Unit 1 auxiliary spray line that was performed in response to NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems." The LRA indicates that this fatigue evaluation is contained in WCAP-14070, "Evaluation of Cook Units 1 and 2 Auxiliary Spray Piping per NRC Bulletin 88-08," July 1994. Provide a copy of WCAP-14070.

Summary of the Original I&M Response to RAI 4.3.1-1:

Copies of the proprietary report, WCAP-14070-P, dated May 2004, and the non-proprietary version of this report, WCAP-14070-NP, dated May 2004, were provided in the referenced letter dated June 16, 2004.

Clarification Requested by the Staff:

Confirm that there is no time dependency for the proprietary frequency specified in the note on page 6-3 of WCAP-14070.

I&M's Supplemental Response to RAI 4.3.1-1:

The frequency noted on page 6-3 of WCAP-14070 for valve leakage is assumed to occur for each of the reactor years of operation for the plant. The cycles are assumed to be for 40 years of operation. Therefore, this frequency is time-dependent and constitutes a TLAA.

I&M will perform one or more of the following activities to address fatigue of the auxiliary spray line piping evaluated in WCAP-14070:

(1) Perform a plant-specific fatigue reanalysis of the auxiliary spray line piping prior to entering the period of extended operation to ensure that cumulative usage factors (CUFs) are below 1.0;

(2) Repair piping at the affected locations;

(3) Replace piping at the affected locations;

(4) Manage the effects of fatigue of the auxiliary spray line piping by an NRC-approved inspection program (e.g., periodic non-destructive examination of the affected locations at inspection intervals to be determined by a method accepted by the NRC). It is expected that the inspections will be able to detect cracking due to thermal fatigue prior

to loss of function. Replacement or repair, if necessary, will then be implemented such that the intended function will be maintained for the period of extended operation.

RAI 4.7.5-1:

In Section 4.7.5 of the LRA, the applicant stated that TLAAs [Time-Limited Aging Analyses] applicable to the steam generators include steam generator tube flow-induced vibration (FIV). The applicant further stated that the time-dependent assumptions made in the D C Cook Unit 1 FIV calculation pertain to the tube corrosion allowance, while for the Unit 2, the assumptions made for the FIV analysis pertain to the tube wear allowance. The applicant was requested to explain why the assumptions made for the FIV analysis models are different between Unit 1 and Unit 2. The applicant was also requested to address the TLAAs on aging effects of tube wear in Unit 1 and corrosion effects in Unit 2, and to provide the necessary aging management programs for the period of extended operation.

I&M Response to RAI 4.7.5-1:

The CNP Unit 1 steam generators were replaced in 2000 with steam generators designed, fabricated, and analyzed by Babcock and Wilcox. The replacement steam generator tube bundles were evaluated to demonstrate that they were adequately supported against detrimental FIV. The analysis accounted for a tube corrosion allowance in the tube models in order to envelop the 40-year design life of the steam generators. The results concluded that the tube bundles were adequately supported over the full range of operating conditions for a 40-year design life. Tube wear susceptibility for CNP Unit 1 was based on an evaluation of the fretting wear damage parameter. The fretting wear damage parameter criterion was developed by Pettigrew et al., "Flow-Induced Vibration Specifications for Steam Generators and Liquid Heat Exchangers," AECL-11401, Chalk River Laboratories, Chalk River, Ontario, November 1995, to provide a design specification to ensure significant fretting-wear is avoided without predicting wear rates. As stated in LRA Section 4.7.5, the 40-year design life of the replacement steam generators encompasses the period of extended operation. Therefore, the design basis of the Unit 1 replacement steam generators (including the FIV analysis) remains valid for the period of extended operation.

The CNP Unit 2 steam generators were replaced in 1988 with steam generators designed, fabricated, and analyzed by Westinghouse. The CNP Unit 2 replacement steam generator tube bundles were evaluated to demonstrate acceptable support against FIV. The Unit 2 analysis determined potential tube wear depths based on calculated interactions between tubes and tube support plates and anti-vibration bars. The analysis compared calculated wear depths to the tube wear allowance and concluded that design margins for local tube wear were acceptable for 40 years of operation. This wear allowance is based on the design set of operating transients. As stated in LRA Section 4.7.5, operating transient cycles are monitored through the Fatigue Monitoring Program, which ensures that the 40-year wear allowance remains valid for the additional 20 years of extended operation. The Unit 2 design basis analysis does not include a corrosion allowance in the tube models.

As described above, the assumptions made for the steam generator FIV analyses are different between Units 1 and 2 because the analyses were performed by two different vendors at two different times using two different methods. Different assumptions were made for the different analyses and either approach is acceptable. There are no Unit 1 FIV analyses involving tube wear assumptions that meet the 10 CFR 54.3 definition of a TLAA. Similarly, there are no Unit 2 FIV analyses involving tube corrosion assumptions that meet the 10 CFR 54.3 definition of a TLAA. Thus, the analysis of loss of material by wear of the tubes is not a TLAA for the Unit 1 replacement steam generator and the analysis of loss of material by corrosion of the tubes is not a TLAA for the Unit 2 replacement steam generator.

As indicated in LRA Table 3.1.2-5, the Water Chemistry Control Program, which is described in LRA Section B.1.40.1, and Steam Generator Integrity Program, which is described in LRA Section B.1.31 and is based on NEI 97-06, *Steam Generator Program Guidelines*, manage the aging effect of loss of material of the steam generator tubes and tube support components. This includes loss of material by the aging mechanisms of corrosion and wear.

Other Aging Management Programs

RAI 3.1-1:

Augmented inspection is recommended for the steam generator shell assembly, item 3.1.1-2 in Table 3.1.1 of the Aging Management Review (AMR). The aging effect is loss of material due to pitting and crevice corrosion, which may not be detected by the inservice inspection and water chemistry control programs. The Standard Review Plan (NUREG-1800) subsection 3.1.2.2.2 recommends an augmented inspection for this aging effect. The applicant states that the Water Chemistry Control Program will be supplemented by the Steam Generator Integrity Program for secondary side components. Neither the Steam Generator Integrity Program description, NEI [Nuclear Energy Institute] 97-06, or the EPRI [Electric Power Research Institute] Steam Generator Examination Guidelines explain such an inspection. Describe the details of the augmented inspection and explain how it will manage the aging effect.

Original I&M Response to RAI 3.1-1:

NUREG-1800, Section 3.1.2.2.2, refers to NRC Information Notice (IN) 90-04, "Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators," dated January 26, 1990, and recommends augmented inspection to manage pitting and corrosion. IN 90-04 states that if general corrosion pitting of the steam generator shell is known to exist, the requirements of ASME Section XI may not be sufficient to differentiate isolated cracks for inherent geometric conditions. However, as discussed in LRA Section 3.1.2.2.2, a review of operating experience indicates that CNP has not experienced general corrosion pitting of the steam generator shell; therefore, the concerns of IN 90-04 are not applicable to CNP. The Primary and Secondary Water Chemistry Control Program and the Inservice Inspection - ASME Section XI, Subsection IWB, IWC, and IWD Program are adequate to manage loss of material due to pitting and crevice corrosion on the internal surfaces of the steam generator shell.

Assessments of potential degradation mechanisms and consideration of industry events are part of the Steam Generator Integrity Program. Augmented inspections of the upper shell-to-transition cone girth welds, if required, will be added to the current Inservice Inspection Program as part of these assessments of potential degradation or operating experience.

Clarification requested for RAI 3.1-1:

Secondary-side inspections are a key part of the response to the initial RAIs. Please provide details for the frequency of the secondary-side steam generator inspections.

I&M's Supplemental Response to RAI 3.1-1:

The secondary side of each steam generator is typically inspected when the steam generator undergoes in-service inspection (eddy current testing of the primary tubing). Technical

Specifications require eddy current inspections to be performed at intervals of not less than 12 nor more than 24 calendar months, and allow a maximum interval of 40 calendar months between primary side inspections based on the observations of previous inspections. However, the Technical Specifications allow less than the full complement of steam generators to be inspected and do not specify a maximum interval between inspections of a specific steam generator.

I&M follows the examination interval recommendations in the EPRI Pressurized Water Reactor Steam Generator Examination Guidelines, which allow a maximum eddy current inspection interval for a specific steam generator up to 72 effective full power months. I&M does not currently intend to extend the inspection interval for either of the primary or secondary side of the steam generator to this maximum interval, but instead anticipates inspecting the secondary side of the steam generators every 36 effective full power months (two refueling cycles) depending on the results of operating experience for each cycle.

RAI B.1.3-1:

[Note - the original RAI included nine sub-parts. The requested clarification only applies to sub-part (f).]

(f) *Describe the corrective actions that would be implemented if coupon test results are not acceptable.*

Original I&M Response to RAI B.1.3-1:

(f) Measurement acceptance criteria are as follows.

- A decrease of no more than 5% in Boron-10 (B-10) content, as determined by neutron attenuation.
- An increase in thickness at any point should not exceed 10% of the initial thickness at that point.

If either of these two criteria are not met, an engineering evaluation is performed to identify the need for further testing (such as blackness testing on the storage racks) or other corrective action. In accordance with the Corrective Action Program, additional actions may be prescribed on a case-by-case basis, based on the evaluation of unacceptable coupon test results.

Clarification Requested by the Staff:

What is the technical basis for the acceptance criteria (5% maximum B-10 decrease and 10% maximum thickness increase)? Has this Boral surveillance program, including the acceptance *criteria, been previously reviewed and approved by the NRC? If these criteria have been approved by the NRC, please provide the reference.*

I&M's Supplemental Response to RAI B.1.3-1:

The purpose of the Boral Surveillance Program is to provide assurance of the neutron absorption capability (i.e., reactivity control) of the Boral panels. The basis for the B-10 areal density acceptance criterion (5% maximum decrease, as determined by neutron attenuation measurements) is that this value is the estimated accuracy of the equipment employed for neutron attenuation measurements. This is acceptable because a 5% variation in B-10 areal density is within the uncertainty tolerance typically applied in nuclear criticality safety analyses.

The purpose of the thickness measurement is to detect significant swelling or blistering. The basis for the thickness acceptance criterion of no more than 10% of the initial thickness is to provide sufficient assurance that swelling will not impact Boral panel performance. For coupons initially of 0.075-inch thickness, the 10% criterion would amount to an increase in thickness of 0.0075-inch. This amount of swelling would not affect performance of the Boral panels because (1) it is within the available space and would not cause binding of a fuel assembly and (2) swelling or blistering does not affect the neutron absorption capability (i.e., reactivity control) of the Boral. The only consequence of excessive swelling, should it occur, would potentially be in binding of a fuel assembly. Although a more restrictive swelling criterion could be applied under laboratory conditions, application of a more restrictive criterion would be difficult under field conditions with contaminated coupons. The 10% criterion is adequate to provide reasonable assurance that corrective actions would be taken before loss of intended function of the Boral panels.

Although the CNP Boral Surveillance Program has not previously been reviewed and approved by the NRC, similar programs have been approved for other licensees. NRC approval of boral surveillance programs for Waterford Steam Electric Station, Unit 3, and Beaver Valley Power Station, Unit 1, are documented in SERs dated July 10, 1998 (Reference 1), and November 1, 1993 (Reference 2). Acceptance criteria are not described in these SERs; however, the CNP Boral Surveillance Program tests are consistent with those approved therein, with acceptance criteria bases described above.

<u>References for Supplemental Response to RAI B.1.3-1</u>

1. Letter from C. P. Patel, NRC, to C. M. Dugger, Entergy Operations, Inc., "Issuance of Amendment No. 144 to Facility Operating License NPF-38 – Waterford Steam Electric Station, Unit 3 (TAC No. M98325)," dated July 10, 1998 [Accession No. ML021790559].
2. Letter form G. E. Edison, NRC, to J. D. Sieber, Duquesne Light Company, "Issuance of Amendment No. 178 to Facility Operating License DPR-66 in Response to Change Request No. 202 Regarding Spent Fuel Pool System (TAC No. M84673)," dated November 1, 1993 [Accession No. ML003767816].

RAI B.1.41-2:

The applicant's program to verify the effectiveness of water chemistry programs is presented in Appendix B.1.41 of the LRA, "Water Chemistry Control -- Chemistry One-Time Inspection." The applicant states that this program will be comparable to GALL Program XI.M32, "One-Time Inspection" and consistent with its general elements, but smaller in scope because one-time inspection of small bore piping is a separate program.

The staff has questions in these two areas:

(1) *The details of B.1.41, "Water Chemistry Control -- Chemistry One-Time Inspection," are not provided in the LRA, and*

(2) *The method for determining where the one-time inspection should be applied to verify the effectiveness of water chemistry control is not clear.*

According to guidance in the GALL report, the elements of the XI.M32 program (One-Time Inspection) include (a) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience; (b) identification of the inspection locations in the system or component based on the aging effect; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined; and (d) evaluation of the need for follow-up examinations to monitor the progression of any aging degradation.

The staff requests that the applicant:

Provide a list of components, material types, environments, and aging effects that will be inspected to verify the effectiveness of the water chemistry program. Justify that these components provide adequate sample size to verify the effectiveness of the water chemistry program for each aging effect managed. The response to previous RAI B.1.41-1 did not provide enough specific information (about the components, materials types, environments, and aging effects that would be inspected) for the staff to complete its review.

I&M Response to RAI B.1.41-2:

NUREG-1801, Section XI.M2, states, "The water chemistry programs are generally effective in removing impurities from intermediate and high flow areas. The Generic Aging Lessons Learned (GALL) report identifies those circumstances in which the water chemistry program is to be augmented to manage the effects of aging for license renewal. For example, the water chemistry control program may not be effective in low flow or stagnant areas. Accordingly, in certain cases as identified in the GALL report, verification of the effectiveness of the chemistry control program is undertaken to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period of operation. As discussed in the GALL report for these specific cases, an acceptable verification program is a one-time inspection of selected components at susceptible locations in the system."

Consistent with the specific cases identified in NUREG-1801 for pressurized water reactors, the CNP components with aging effects managed by water chemistry control and the Chemistry One-Time Inspection Program are, piping, fittings, valve bodies, pump casings, tanks, heat exchangers, and other in-line piping components such as orifices and strainer housings. A sample of these components, in susceptible locations, representative of the material and environment combinations noted in the NUREG-1801 cases will be used to verify the effectiveness of the water chemistry control programs in managing cracking and loss of material. The applicable material and environment combinations that are noted in NUREG-1801 as requiring a one-time inspection are carbon steel exposed to steam or treated water and stainless steel exposed to treated water.

In addition to the material and environment combinations noted in NUREG-1801 as requiring a one-time inspection, I&M has stated in RAI responses that the Chemistry One-Time Inspection Program will verify the effectiveness of the water chemistry control programs in managing aging effects for additional material and environment combinations. Specifically, in the referenced June 30, 2004, letter, I&M stated that the Chemistry One-Time Inspection Program will verify effectiveness of the chemistry programs in managing: (1) loss of material of copper alloy in a treated water environment (RAI 3.2-11); (2) loss of material of carbon steel in a treated water environment and stainless steel in a borated water environment for components in engineered safety features systems (RAI 3.2-12); (3) loss of material and fouling of the copper alloy tubes in the turbine-driven auxiliary feedwater pump turbine bearing lube oil cooler and governor oil cooler (RAIs 3.4-7 and 3.4-8); and (4) loss of material and cracking for stainless steel and loss of material for carbon/alloy steel in treated water and steam environments (RAIs 3.4-10 and 3.4-11). In this letter, in the supplemental responses to RAIs 3.3.2.1.9-4 and 3.3.2.1.9-6, I&M states that the Chemistry One-Time Inspection Program will include inspection of surfaces of the copper alloy security diesel lube oil and jacket water coolers, and in the supplemental responses to RAI 3.3.2.1.11-1, I&M commits to a one-time inspection of various components listed in LRA Table 3.3.2-11 that are exposed to raw and untreated water environments.

Because the CNP Chemistry One-Time Inspection Program is a new program, a list of specific components and locations to be inspected is not available. Selection of an appropriate sample population (and sample size) will be based on material, environment, time in service, aging effects, and operating experience as specified in NUREG-1801, Section XI.M32. The sample will include components in stagnant or low-flow areas that are most susceptible to aging. The use of the NUREG-1801 criteria to determine an adequate sample size is consistent with the previously approved licensee position documented in NUREG-1786, *Safety Evaluation Report Related to the License Renewal of R. E. Ginna Nuclear Plant* [Accession No. ML040640687].

NUREG-1801, Section XI.M32, also recommends use of the One-Time Inspection Program, in conjunction with the Water Chemistry Control Program, to verify that cracking is not occurring in small-bore RCS and connected systems piping, where the ASME Code does not require volumetric examination during inservice inspection. LRA Section B.1.30 states that the Small Bore Piping Program, which is consistent with the NUREG-1801 One-Time Inspection Program, will be used to manage cracking in small-bore Class 1 piping (less than 4-inch nominal pipe size) that is directly connected to the RCS. The LRA also states that volumetric examinations will be performed. These program attributes satisfy the one-time inspection recommendations in the NUREG-1800, *Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants*, for small-bore RCS and connected systems piping.

Reference for RAI B.1.41-2

Letter from M. K. Nazar, I&M, to NRC Document Control Desk, "Donald C. Cook Nuclear Plant, Units 1 and 2, License Renewal Application - Response to Requests for Additional Information on Engineered Safety Features, Auxiliary Systems, and Steam and Power Conversion Systems (TAC Nos. MC1202 and MC1203)," dated June 30, 2004 [Accession No. ML041890378].

LIST OF REGULATORY COMMITMENTS

The following table summarizes the actions committed to by Indiana Michigan Power Company (I&M) in this document. Any other actions discussed in this submittal represent intended or planned actions by I&M. They are described to the Nuclear Regulatory Commission (NRC) for information and are not regulatory commitments.

Commitment	Date
I&M's Supplemental Response to RAI B.1.27-2: *[NOTE: This commitment supplements I&M's LRA commitment to develop and implement a Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program prior to the period of extended operation.]* I&M will submit the Reactor Vessel Internals Plates, Forgings, Welds, and Bolting Program for NRC Staff review and approval three years prior to the period of extended operation.	Unit 1: October 25, 2011 Unit 2: December 23, 2014
I&M's Supplemental Response to RAI 2.3.3.8-6: *[NOTE: This commitment supplements I&M's LRA commitment to enhance the Preventive Maintenance Program prior to the period of extended operation.]* The Preventive Maintenance Program will manage loss of material for the EDG exhaust silencer internals. Visual inspections of the EDG exhaust silencer internals will be performed before the period of extended operation as part of the Preventive Maintenance Program. The frequency of future inspections will be based on the initial inspection results.	Unit 1: October 25, 2014 Unit 2: December 23, 2017
I&M's Supplemental Response to RAI 3.6-2: *[NOTE: This commitment supplements I&M's LRA commitment to develop and implement a Non-EQ Instrumentation Circuits Test Review Program prior to the period of extended operation.]* An insulation resistance (IR) test method, such as TDR, will be continued through the period of extended operation as part of the Non-EQ Instrumentation Circuits Test Review Program. The test frequency of instrumentation cables that are in the scope of this program, but are disconnected during calibration, shall be determined by I&M based on engineering evaluation, but will not be less than once per ten years.	Unit 1: October 25, 2014 Unit 2: December 23, 2017

Commitment	Date
<u>I&M's Supplemental Response to RAI 3.3.2.1.11-1</u> *[NOTE: This commitment supplements I&M's LRA commitment to develop and implement a Chemistry One-Time Inspection Program prior to the period of extended operation.]* I&M will include the auxiliary steam system copper heater coils, cast iron strainer housings, and carbon steel traps exposed to an internal steam environment in the Chemistry One-Time Inspection Program, which is described in LRA Section B.1.41. I&M will include these 10 CFR 54.4(a)(2) components [i.e., components in the CONT, DRAIN, PASS, RMS, RWD, and SD systems that are subject to aging management review, and may be pressurized and contain raw or untreated water.] in the Chemistry One-Time Inspection Program. Loss of material from these components, if any, should progress slowly. The one-time inspection of these components will provide assurance that loss of material is occurring at a rate slow enough to ensure that the intended functions of the components will be maintained during the period of extended operation. This one-time inspection will be performed near the end of the current operating term. The visual inspections will identify indications of loss of material. If loss of material is identified, an evaluation will be performed to confirm that the rate is sufficiently slow that loss of intended function will not occur during the period of extended operation. For material and environment combinations with no evidence of loss of material or with very gradual loss of material, no further actions will be taken. For material and environment combinations with loss of material rates such that loss of intended function could occur during the period of extended operation, corrective actions will be taken in accordance with the Corrective Action Program. Appropriate corrective actions may consist of component replacement or additional inspections for components with the material and environment combination in which the excessive loss of material is found.	Unit 1: October 25, 2014 Unit 2: December 23, 2017

Commitment	Date
I&M's Supplemental Response to RAI 4.3.1-1: The frequency noted on page 6-3 of WCAP-14070 for valve leakage is assumed to occur for each of the reactor years of operation for the plant. The cycles are assumed to be for 40 years of operation. Therefore, this frequency is time-dependent and constitutes a TLAA. I&M will perform one or more of the following activities to address fatigue of the auxiliary spray line piping evaluated in WCAP-14070: (1) Perform a plant-specific fatigue reanalysis of the auxiliary spray line piping prior to entering the period of extended operation to ensure that cumulative usage factors (CUFs) are below 1.0; (2) Repair piping at the affected locations; (3) Replace piping at the affected locations; (4) Manage the effects of fatigue of the auxiliary spray line piping by an NRC-approved inspection program (e.g., periodic non-destructive examination of the affected locations at inspection intervals to be determined by a method accepted by the NRC). It is expected that the inspections will be able to detect cracking due to thermal fatigue prior to loss of function. Replacement or repair, if necessary, will then be implemented such that the intended function will be maintained for the period of extended operation.	Unit 1: October 25, 2014 Unit 2: December 23, 2017