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U.S. Nuclear Regulatory Commission
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Monticello Nuclear Generating Plant
Docket 50-263
License No. DPR-22

Response to Request for Additional Information Regarding the Monticello License Renewal Application (TAC No. MC6440)

References: 1) NMC letter to NRC, "Application for Renewed Operating License," dated March 16, 2005 (ADAMS Accession No. ML050880241)

2) NRC letter to NMC, "Requests for Additional Information for the Review of the Monticello Nuclear Generating Plant, License Renewal Application," June 21, 2005 (ADAMS Accession No. ML051720593)

3) NMC letter to NRC, "Response to Request for Additional Information Regarding the Monticello License Renewal Application dated July 21, 2005," (ADAMS Accession No. ML052080040)

4) NRC letter to NMC, "Request for Additional Information for the Review of the Monticello Nuclear Generating Plant License Renewal Application," July 20, 2005 (ADAMS Accession No. ML052020005)

Pursuant to 10 CFR 54, the Nuclear Management Company, (NMC) LLC submitted a License Renewal Application (LRA) (Reference 1) to renew the operating license for the Monticello Nuclear Generating Plant (MNGP).

By letter dated June 21, 2005, the U.S. Nuclear Regulatory Commission (NRC) issued a Request for Additional Information (RAI) regarding the LRA for the MNGP (Reference 2). An NMC response dated July 21, 2005, (Reference 3) provided the NMC response to Reference 2 with the exception of RAI 4.5-1. A response to RAI 4.5-1 was delayed to resolve an industry issue related to the use of service temperatures for carbon steel and the low alloy steel environmental fatigue life correction factor (F_{en}) values. The response to RAI 4.5-1 is now complete and is provided in Enclosure 1.

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By letter dated July 20, 2005, the NRC issued an additional RAI related to the LRA for the MNGP (Reference 4). The response to Reference 4 is provided in its entirety in Enclosure 2.

This letter contains no new regulatory commitments.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on August 16, 2005.

John T. Conway
Site Vice President, Monticello Nuclear Generating Plant
Nuclear Management Company, LLC

Enclosures (2)

cc: Administrator, Region III, USNRC
Project Manager, Monticello, USNRC
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ENCLOSURE 1

RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION DATED JUNE 21, 2005, NRC RAI 4.5-1

A. NRC RAI 4.5-1

Section 4.5 of the LRA discusses the evaluation of the impact of the reactor water environment on the fatigue life of the locations identified in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components." The environmental fatigue usage for the core spray nozzle (safe end) is much lower than the fatigue usage of the core spray nozzle (without environmental effects) provided in Table 4.3.3-1 of the LRA. Provide the basis for the reported usage factors. In addition, discuss the calculation of the F_{en} multipliers used for each of the NUREG/CR-6260 locations. Provide the calculated F_{en} multipliers.

NMC Response

The difference in the values for the core spray nozzle identified in LRA Table 4.3.1-1 (reference to Table 4.3.3-1 above appears to be incorrect) and the NUREG/CR-6260 calculation results shown in License Renewal Application (LRA) Section 4.5 are due to differences in evaluation methods. The fatigue usage of 0.645 identified for the core spray nozzle in Table 4.3.1-1 uses cycle accumulations determined as part of the Monticello Nuclear Generating Plant (MNGP) fatigue monitoring program. This program provides for the identification of cycles by transient type, extrapolates those cycles to 60 years, and calculates fatigue by a simple ratio (projected cycles/design basis cycles, 116/180). NUREG/CR-6260 calculations utilized a stress based evaluation method from which, based on the alternating stress for discrete load pairs, allowable cycles were determined. Using fatigue monitoring program cycle counting results, cumulative fatigue was then determined by a summation of the projected cycles/allowable cycles multiplied by the environmental fatigue life correction factor (F_{en}) for each load pair. Comparing the results of each of these methods substantiates the greater conservatism associated with the MNGP fatigue monitoring program methodology.

F_{en} multipliers were calculated in accordance with the NUREG/CR-6583 for carbon/low alloy steel locations and NUREG/CR-5704 for stainless steel locations. Relevant parameters for F_{en} calculation such as fluid surface temperature, sulfur content, temperature regime, oxygen content, and strain rate were identified for each location. F_{en} multipliers for all locations were calculated for a reactor water coolant environment with the hydrogen water chemistry (HWC) system operating and for an environment without the HWC (NWC) operating. Based on the expected exposures to HWC and NWC, environmental fatigue was calculated by multiplying the fatigue usage by the composite F_{en} multiplier.

Recently, industry implementation of F_{en} temperature input parameter (T) has been questioned for carbon and low-alloy steel locations. Specifically, it has been noted that the service temperature as opposed to 25 °C which is required for a fatigue life correction factor that is defined relative to air (e.g., the "0.00124T" term in equations 6.5a and 6.5b of NUREG/CR-6583) has been used. We have completed a review of calculations that support the LRA, found that this error is applicable to MNGP, and revised the calculations accordingly. All affected locations continue to meet acceptance criteria for fatigue. The following revised environmental fatigue usages are provided. For comparison, original values reported in LRA Section 4.5 are also included.

Location	Mat'l[1]	LRA Section 4.5 Table (60 Year U_{env})	Env. Multiplier (F_{en})	Revised Multiplier[4] (F_{en})	Revised 60 Year U_{env}
RPV Shell	CS	0.569	6.21	8.16	0.748
FWTR Nozzle/SE	CS	0.938	2.12	1.97[3]	0.872[3]
RI Nozzle/SE	SS	0.749	4.81	NC[2]	NC[2]
CS Nozzle/SE	CS	0.194	1.88	2.60	0.268
Recirc./RHR Piping	SS	0.864	2.55	NC[2]	NC[2]
FWTR/RCIC Piping	CS	0.513	6.21	8.16	0.673

Notes:
1. CS = carbon steel, SS = stainless steel
2. NC = no change, these locations (SS) are not affected by the revised temperature (T) used in the CS F_{en} calculations.
3. Reduction due to removal in conservative treatment of T* in calculation of F_{en} (originally 549 °F as opposed to transient maximum of 391 °F).
4. Revised to account for T=25 °C, F_{en} relative to air.

The feedwater nozzle (FWTR) safe ends (SE), core spray (CS) nozzle safe ends, recirculation inlet (RI) nozzle safe ends, and the recirculation/residual heat removal (RHR) piping locations were replaced in the 1980s. Consequently, their exposure to an HWC environment as a percentage of in-service time has increased which contributes to the variance in F_{en} multipliers identified herein.

ENCLOSURE 2

RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION DATED JULY 20, 2005

2.1 Scoping and Screening Methodology

A. NRC RAI 2.1-1

Monticello Operations Manual A.6, "Acts of Nature," Revision 20, provides instructions for the response of Monticello Nuclear Generating Plant personnel to extreme natural conditions. Tornados, external flooding, high river water temperature, low river water flow/level, high wind conditions, heavy snowfall, and high ambient (outside) air temperature are addressed in Operations Manual A.6. Section 5 of A.6 provides instructions for protecting structures from flooding in the event that Mississippi River floodwaters are predicted to exceed specific elevations. For example, steel plates are required to be bolted over specific structure openings and suitable steel plates are stored onsite to accomplish this task. Another example of an action in Section 5 of A.6 to prevent flooding is to remove the intake structure Amertap hatch covers and install the original floor hatches. The NRC's audit team noted that equipment stored for use, such as steel plates and floor hatches, was not included in the scope of license renewal. The applicant indicated during the audit that it planned to reevaluate its original conclusion that this equipment is not in the scope of license renewal.

10 CFR 54.4(a) describes the criteria for determining systems, structures, and components (SSCs) that are required to be within the scope of license renewal. The staff requires additional information to complete its review. Specifically, the staff requests the applicant:

(a) Provide a technical basis for not including in the scope of license renewal, equipment stored onsite that is required by station procedures to be installed during emergency or abnormal conditions in accordance with the current licensing basis; or

(b) Describe the methodology used to ensure that all equipment stored onsite which station procedures require to be installed during emergency or abnormal conditions, in accordance with the current licensing basis, is addressed in license renewal scoping. In your response, indicate the documentation sources reviewed to ensure that all such equipment was identified and describe additional scoping evaluations performed to address the criteria in 10 CFR 54.4(a). List any additional SSCs included within scope as a result of your efforts, and list those SSCs for which aging management reviews were conducted. For each SSC describe the aging management programs, as applicable, to be credited for managing the identified aging effects.

NMC Response

(a) Further investigation determined that the description of the steel plates in the Current License Basis (CLB) and their dedicated use for external flood protection to serve as flood barriers for specific Class I structure openings and penetrations warranted their inclusion in license renewal (LR) scope per 10 CFR 54.4 (a)(2). Similarly, the Intake Structure original floor steel hatch covers, staged to provide external flood protection as described in the MNGP Operations Manual, Section A.6 (Acts of Nature), warranted their inclusion in license renewal scope.

(b) The following discussion characterizes the methodology MNGP used to ensure that all equipment stored onsite, which station procedures require to be installed during emergency or abnormal conditions in accordance with the current licensing basis to support a 10 CFR 54.4(a) license renewal intended function, is addressed in license renewal scoping. This review provides a list of documentation sources reviewed to ensure equipment stored onsite is identified, along with equipment scoping evaluations, to address the criteria in 10 CFR 54.4(a). A list is provided of the additional systems, structures, and components (SSCs) within scope of license renewal as a result of this effort, and those SSCs for which aging management reviews were conducted. Aging management programs when applicable are included and aging effects identified.

Stored equipment is characterized as equipment not physically installed nor normally in service, but rather dedicated (reserved) for use in an application where it would perform a license renewal intended function when installed. This includes equipment stored in the warehouse or staged at other plant locations within the owner controlled area to facilitate its timely use. Stored equipment is further defined as equipment that:

1. Is not physically installed as part of a license renewal SSC.
2. When installed, is required to support a SSC function(s) meeting the requirements of 10 CFR 54.4 (i.e., identified in the CLB and required for a Design Basis Event or regulated event - this does not include beyond design basis event conditions),
3. Is staged, dedicated, or reserved exclusively for use in supporting SSC function(s) meeting the requirements of 10 CFR 54.4 through the period of extended operation (i.e., not a commodity that is readily available or that can be fabricated within the required timeframe from a number of different onsite or offsite sources),
4. Is not the tools and supplies required to install the equipment unless these items are an integral part of the installed component

and necessary for it to perform its intended function (e.g., connection hoses or cables),

5. Is not a consumable (consumables comprise such items as packing, gaskets, component mechanical seals, O-rings, structural sealants, oil, grease, component filters, system filters, fire extinguishers, fire hoses, and air packs), and

6. Is expected to be able to perform its function throughout the period of extended operation when needed, i.e., it is not periodically tested and replaced on condition.

Applying the above criteria, most stored equipment is not within the scope of license renewal or screens out and did not require an aging management review. Many items are periodically replaced on condition or considered consumables. The only stored equipment at the MNGP requiring aging management review is:

- Steel plates, stored outside, that are dedicated for use during postulated external floods per the MNGP Updated Safety Analysis Report (USAR) Section 12.2.1.7.1 and Procedure A.6,

- Steel hatch covers, stored in the warehouse, that are dedicated for external flood use per the MNGP Procedure A.6, and

- The gasoline powered portable diesel fuel oil transfer pump (P-229) (previously included in LR scope per 10 CFR 54.4(a)(3))

The steel plates and steel hatch covers are additional SSCs included within scope as part of this effort. For the gasoline powered portable diesel fuel oil transfer pump, aging management review was previously conducted as part of the MNGP DGN license renewal system per the System/Structure Scoping and Screening Output Report for Emergency Diesel Generators. These SSCs are not routinely replaced, described in the USAR, support CLB design base events or 10 CFR 54.4 regulated events, are considered dedicated and/or uniquely designed to fulfill specific LR intended functions, and are not expected to be replaced or need refurbishment during the period of extended operation.

Other stored equipment was determined not to require aging management. Stored equipment was identified using keyword searches of the USAR and plant operations manuals/procedures. These SSCs do not perform an in-scope function per 10 CFR 54.4 and/or are replaced based on condition. Key word searches included "stage", "stages", "staged", "store", "stored", "stores", "storage", "temporary", "plate", "plates", "dedicate", "dedicates", "dedicated", "dedication", and "portable". The plant procedure for addressing acts of nature was reviewed in detail. Extensive walk downs of the plant warehouses were performed to identify other possible sources of staged equipment in addition to those identified in the USAR or by plant procedures. A number of items were identified that are addressed in more detail in project documents. In summary, these items did not met the above definition of stored equipment because:

- They met the definition of consumables (e.g., breathing apparatus replaced on condition, nitrogen bottles),
- They screened out as active equipment (e.g., radios used for communications),
- They were staged to support beyond design basis events only and are not within the scope of 10 CFR 54.4(a) (e.g., portable radiation monitors and fans), and
- They are not dedicated to a specific use, replaced on condition, and readily available from a number of onsite and offsite sources (e.g., tools).

As a result of this effort, the following additional components are in scope requiring aging management. The MNGP Structures Monitoring Program will be used to mange these components for the aging effect loss of material:

- Steel plates, stored outside, that are dedicated for use during postulated external floods.
- Steel hatch covers, stored in the warehouse, that are dedicated for external flood use.

B. NRC RAI 2.1-2

Monticello License Renewal Procedure LRP 2-1, "Scoping and Screening for License Renewal," Revision 3, Section 4.2.15, provides guidance for establishing system boundaries for non-safety-related (NSR) piping systems connected directly to safety-related (SR) piping systems. The procedure states, in part, that for NSR connected to SR, the NSR SSCs should be included up to the first seismic anchor past the SR/NSR interface, and that the anchor should also be identified on the boundary drawings. Monticello Technical Report, TR-011, "Component identification for SSCs Within Scope of 10 CFR 54.4(a)(2) Non-Safety Affecting Safety," Revision 3, states, in part, that a review of piping analyses provided information to extend the piping system to the first anchor. In cases where a true anchor did not exist, the piping analysis was extended sufficiently far to ensure the NSR portion would not have an effect on the SR portion. Typically, this was at least extended to encompass two restraints in each orthogonal direction. In those few cases where such restraints did not exist in each orthogonal direction, the boundary was extended to an equivalent anchor such as a wall. As an example, the applicant stated that in certain cases of small-bore piping (i.e., 2" or less) grouted wall penetrations served as the equivalent anchor location. Based on the staff's review of the applicant's scoping evaluation related to the 10 CFR 54.4a(2) criterion, the staff requires additional information to complete its review. Specifically, the staff requests the applicant:

(a) Provide the technical basis for establishing the grouted wall penetrations as an equivalent anchor location; and

(b) Verify that non-grouted wall penetrations were not used as equivalent anchor locations for NSR piping systems connected to SR piping systems.

NMC Response

(a) The MNGP piping analysis specification defines an anchor as an "engineered component designed to limit translation and rotation in three orthogonal directions". As long as the wall/floor penetration is grouted solid, it meets the criteria for an anchor and can be used as an equivalent anchor for license renewal. The grout used to fill the space between the pipe and the surrounding concrete is as strong or stronger than the concrete and provides a means to transfer the forces and moments to the surrounding concrete. In addition, the walls/floors are designed for piping reaction loads.

Site piping analysis practice is to consider grouted penetrations as anchors. A review of the non safety-related (NSR) piping attached to safety related (SR) piping identified 17 instances where a wall/floor penetration is considered an equivalent anchor. Of these, 14 are based on an existing piping analysis. Most of these penetrations are grouted, additionally; several of these penetrations are at points where the pipe goes underground.

In two of the three instances where the equivalent anchor is not based on an existing piping analysis, the pipe runs underground on the other side of the penetration. For the remaining instance, the piping on the other side of the penetration is included in-scope for the spaces approach.

Industry piping analysis practice also considers grouted penetrations as anchors. Chapter B4, "Stress Analysis of Piping Systems", of the Piping Handbook, 7th Edition, identifies building penetrations as possible anchors. In addition, ASCE Paper, Seismic Design and Retrofit of Piping Systems, July 2002, Section 5.1 describes, "fully constrained wall penetrations" as typical anchor points for piping analysis.

Therefore, based on plant and industry piping analysis practices, using grouted penetrations as equivalent anchors for NSR lines attached to SR lines, without an existing piping analysis, is acceptable.

(b) A walkdown was performed of the one instance where a grouted penetration is considered an equivalent anchor and is not based on an existing piping analysis or does not go underground. The walkdown indicated that this penetration is grouted.

3.2 Engineered Safety Features

C. NRC RAI 3.2-1

In Table 3.2.2-4 of the LRA, the applicant proposes to manage the aging effect of heat transfer degradation due to fouling of the copper alloy heat exchanger tubes in an external lubricating oil environment with a One-Time Inspection Program. The staff requests the applicant provide the following:

(a) Specific material composition of the copper alloys.

(b) Oil analysis program and/or other methods to ensure that the lubricating oil remains free of contaminants, which might degrade the tubing.

(c) Preventive maintenance procedures to ensure that heat transfer degradation does not reach unacceptable levels.

NMC Response

(a) The High Pressure Coolant Injection System (HPC) lubricating oil cooler (E-206) is an American Standard (Whitlock) cooler of carbon steel construction with 5/8" O.D. Admiralty tubes in accordance with the vendor's technical manual. Admiralty brass is composed of 71Cu-28Zn-1Sn.

(b) Lube oil samples from the HPC lube oil cooler are obtained every six months in accordance with MNGP site procedures and the sample results are evaluated and trended. These parameters include iron, copper, etc. for indications of wear, dielectric, viscosity, etc. for chemical analysis and water, silicon, etc. for indication of contamination. Sampling is performed IAW EPRI 1007459 (November 2002) for the HPC lube oil cooler. Electric Power Research Institute (EPRI) Report 1007459 recommends that "oil moisture content be verified on a monthly basis and that acidity, viscosity, and particle count be verified each quarter until a data trending program can justify extending the inspection frequency." This frequency, based upon data trending results, was extended to a six-month frequency. Any indication of an anomalous condition or adverse trend will result in an investigation under the site corrective action program. All results have been acceptable to date to ensure that the lubricating oil remains free of contaminants that could potentially degrade the heat exchanger (cooler) tubes with the last sample taken and evaluated in March 2005.

(c) Preventive maintenance procedures are in effect to both clean and inspect the HPC lube oil cooler and perform eddy current testing every three cycles. Eddy current testing was last performed in January 2000 on the originally installed cooler. All tubes were inspected. No tubes required plugging and no unacceptable defects were detected.

D. NRC RAI 3.2-2

In Table 3.2.2-4 of the LRA, the applicant states that heat transfer degradation due to fouling of the copper alloy heat exchanger tubes in a steam environment will be managed with Plant Chemistry and One-Time Inspection Programs. The applicant further states that neither the components nor the material and environment combination are evaluated in NUREG-1801. The staff requests the applicant verify that the steam in the heat exchangers identified above originates from treated water. In addition, the applicant is requested to provide justification for not considering erosion and flow accelerated corrosion (FAC) as aging mechanisms for this material and environment combination.

NMC Response

Per LRA 2.3.2.4, High Pressure Coolant Injection (HPC) System, "The HPC turbine is driven with steam from the RPV. Two sources of water are available for the HPC System. Normally, water is supplied to the suction of the HPC pump from the two condensate storage tanks (CST). When the level in either CST falls to the predetermined setpoint, the pump suction is automatically transferred to the suppression pool." The HPC heat exchanger in question is the HPC Gland Seal Condenser, E-204, which condenses the gland seal steam from the HPC turbine by using cooling water from the discharge of the HPC pump. Therefore, the steam in this heat exchanger is produced by the treated water in the RPV.

EPRI NSAC 202L, R2, "Recommendations for an Effective Flow-Accelerated Corrosion (FAC) Program", Page 4-3, allows an exclusion from FAC for systems which operate less than 2% of the time, which would be applicable to this HPC condenser. In addition, this component is not subject to high velocity, constricted flow, or fluid direction changes. Therefore, in accordance with EPRI 1003056, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 3", loss of material due to erosion or FAC are not potential aging mechanisms.

3.3 Auxiliary Systems

E. NRC RAI 3.3.2.3-1

LRA Table 3.3.2-4 identifies stress cracking corrosion (SCC) as an aging effect requiring management for stainless steel piping and fittings in a primary containment air environment. To manage this aging effect, the applicant credits the System Condition Monitoring Program, LRA Section B2.1.32, which utilizes visual inspections of component external surfaces for detection of aging effects. Therefore, the applicant is requested to provide operating experience or other bases used for determining that SCC is an aging effect in this environment. Also, since methods such as VT-1, liquid penetrant, or volumetric inspections are used to detect SCC, the applicant is requested to identify the methods and acceptance criteria used by the System Condition Monitoring Program to detect SCC for these components.

NMC Response

Data suggests that temperature is an important factor in stress corrosion cracking (SCC) and that SCC is seldom found at temperatures below 140 degrees F. However, a review of plant operating experience revealed two locations where cracking was observed on the exterior of the Control Rod Drive System (CRD) withdrawal lines, prompting NMC to manage cracking on the exterior of the stainless steel CRD lines located inside containment.

In 1998, during performance of the visual walkdown portion of the reactor coolant pressure boundary leakage test, a crack was identified on a CRD withdrawal line within the drywell. The specific CRD is CRD 34-27. Failure analysis performed by a metallurgical laboratory revealed the cause to be transgranular stress corrosion cracking (TGSCC) due to chloride attack of the external surface. This evaluation showed the cracking to originate from the outside diameter inwards. Also, the metallurgical laboratory found chloride in the through wall flaw. The source of the chloride contamination was not positively identified. The leaking pipe was in an area located directly under catwalks. These open areas are more vulnerable to contamination due to personnel traffic and potential for spills.

As a result of the leak, the following inspections were made during the 1998 refueling outage:

- All lines were VT-2 inspected during the ASME Code, Section XI, reactor coolant pressure boundary leakage test. No leaks were found after the cracked piping was replaced.

- All elbows (where the vertical run turns horizontal for penetration of the biological shield) were visually inspected. There were no indications.

- Dye penetrant testing on the elbows of 14 withdraw lines in the same bundle as CRD 34-27 (outside of the biological shield, with the exception of an elbow on CRD 38-27 which was inside the biological shield.) was conducted. No indications were found.

During the 2000 outage, the accessible CRD piping had been wiped down and foreign material, including tape, was removed. After the piping was cleaned, an inspection of 504 one-foot long sections of all accessible CRD insert and withdrawal lines from the hydraulic accumulator units (HCUs) to the reactor pedestal was implemented. A crack indication was found on CRD withdrawal line 14-27 inside the drywell. The drywell pipe section contained a defect greater than 10% through wall. The apparent cause of the indication appears to have been chloride induced SCC. The indication was identified as being under a piece of tape on a vertical section of the withdraw line. The laborer removing the tape from the area with the relevant indication noted that that particular piece of tape was different from the others removed in that it was both discolored and difficult to remove. It is possible, although unlikely, that the chlorides necessary for TGSCC leached from this tape. However, a more plausible explanation is that chloride contaminated water from another source dripped down the pipe and the tape acted as a crevice, providing a spot for the aqueous chlorides to begin their attack. A source of aqueous chlorides leaking from above would be consistent with the relevant conditions found during the 1998 refueling outage.

In view of this plant specific operating experience, NMC conservatively assumed cracking on the external surface of the CRD pipes inside the drywell despite the extensive testing already conducted. The cracking will be managed using the System Condition Monitoring Program. The System Condition Monitoring Program is an existing plant specific program. This program manages aging effects for normally accessible, external surfaces of piping, tanks, and other components and equipment within the scope of license renewal. The aging effects are to be managed through visual inspection to look for degradation conditions such as crack like indications and corrosion.

Crack like indications will be entered into the corrective action process for evaluation. The evaluation will include appropriate acceptance criteria based on applicable code specifications and industry practices such as EPRI. The evaluation will consider the need for further surface examinations such as liquid penetrant or volumetric inspection to determine the extent of condition.

F. **NRC RAI 3.3.2.3-2**

LRA Tables 3.3.2-6 and 3.3.2-8 identify heat transfer degradation due to fouling as an aging effect requiring management for copper heat exchangers (heat transfer and pressure boundary functions) in a lubricating oil environment. The applicant credits the One-Time Inspection Program to manage this aging effect. Previous staff positions stated the One-Time Inspection Program provides measures to verify the effectiveness of an aging management program and to confirm the absence of an aging effect. For fouling of heat exchangers in a lubricating oil environment, mitigation of the aging effect is dependent on a lubricating oil monitoring program to maintain the integrity of the oil. Therefore, an acceptable aging management program should include a lubricating oil monitoring program to mitigate the aging effect and a one-time inspection to verify the effectiveness of the mitigation program. The applicant is requested to identify an Aging Management Program to mitigate the effects of fouling in the heat exchangers during the period of extended operation and verify the effectiveness of that program with a one-time inspection.

NMC Response

Table 3.3.2-6, Emergency Diesel Generators System (EDG) and Table 3.3.2-8, Emergency Service Water System (ESW) identify copper alloy heat exchanger tubes for both the EDG lube oil coolers and RHR Service Water (RSW) pump motor thrust bearing oil coolers with lubricating oil as an external environment for these Auxiliary Systems.

The NMC position concerning the potential aging effect of heat transfer degradation due to fouling in a lubricating oil environment is that degradation effects are insignificant for lubricating oil systems if the oil remains free of water and other contaminants. Under these conditions, lubricating oil systems and associated components have few, if any, significant aging effects. The purity of the EDG and ESW lubricating oil systems is maintained and chemically analyzed periodically. For equipment not normally in operation during power operation such as the EDG lube oil coolers and the RSW motor thrust bearing oil coolers, periodic testing of the equipment, in conjunction with oil sampling, is performed to detect any contaminants or water in the oil.

Lubricating oil is usually non-corrosive and flow rates for lube oil systems are typically low. Strict controls for the quality and purity of the lubricating oil procured and scheduled sampling techniques and parameters monitored are requirements of the MNGP lubricating oil sampling procedures. Very little corrosion occurs in lubricating oil systems due to low oxygen content, the fact that lubricating oils are not good electrolytes and purification systems are generally installed and/or corrosion inhibitors added to maintain the lubricating oil free of corrosion products.

Lube oil samples for the EDG lube oil coolers are obtained quarterly and samples for the RSW pump motor thrust bearing oil coolers are obtained annually in accordance with MNGP site procedures. The sample results are evaluated and trended for these components. Any indication of an anomalous condition or adverse trend will result in an investigation under the site corrective action program. All sample results have been acceptable to date to ensure that the lubricating oil remains free of moisture and contaminants that could potentially degrade the heat exchanger tubes with the last samples taken and evaluated for both the EDG and ESW systems in 2005. Although MNGP operating experience did result in the replacement of the EDG lube oil coolers due to the lead solder joints and resultant exfoliation corrosion, this was a design issue and not age related (Institute of Nuclear Power Operations SOER 80-04).

Based on the above procurement and sampling requirements to maintain the integrity of the lubricating oil and MNGP plant-specific operating experience that confirms the absence of this aging effect, MNGP conservatively credits the One-Time Inspection Program to verify the absence of the aging effect of heat transfer degradation due to fouling for these components in the EDG and ESW Systems. The MNGP One-Time Inspection Program will use the Corrective Action Program to evaluate indications or relevant conditions of degradation. The need to increase the number of selected components for inspection will also be evaluated when indications or relevant conditions of degradation or unacceptable conditions are found.

G. NRC RAI 3.3.2.3-3

Tables 3.3.2-3 and 3.3.2-16 identify no aging effects for rubber expansion joints in a raw water environment. Previously, the staff has identified hardening and loss of strength as aging effects for elastomer components in this environment and recommended the Open-Cycle Cooling Water Program to manage these aging effects. The applicant is requested to identify an Aging Management Program to manage hardening and loss of strength for rubber expansion joints in a raw water environment, or provide the technical basis for why these aging effects are not applicable to MNGP.

NMC Response

Several EPRI Technical Reports and Industry handbooks were reviewed for aging of elastomers. A summary of the review is provided below.

EPRI Report 1008035, "Expansion Joint Maintenance Guide", Revision 1, May 2003, Table 5-4, rates elastomers against oxidation, tensile strength, and radiation. Elastomers, such as Neoprene, Natural Rubber, Chlorobutyl, Buna-N, Viton, and EPDM, are rated as good or better in the categories of oxidation, tensile strength, and radiation.

EPRI Report NP-6608, "Shelf Life of Elastomeric Components," May 1994, Appendix A, provides curves that describe the change in physical properties for different elastomers as they undergo natural aging. The figures demonstrate that there is very little change in the hardness and tensile strength of elastomers over a 33 year period.

EPRI Report NP-6408, "Guidelines for Establishing, Maintaining, and Extending the Shelf Life Capability of Limited Life Items (NCIG-13)", May 1992, section 4.3.2, states that test results demonstrated Viton and Neoprene as having excellent weather resistance and are therefore UV resistant. Section 4.4.2 states that these elastomers are also highly resistant to ozone.

The Parker O-Ring Handbook, Page 2-24, in a discussion about aging of rubber seals states, "It is environment and not age that is significant to seal life, both in storage and actual service." The following is a discussion of the role of environment on the aging of elastomers.

EPRI 1003056, November 2001, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 3, states "For a complete discussion of the aging effects of typical elastomers used in nuclear plants, the applicant is referred to EPRI TR-114881, "Aging Effects for Structures and Structural Components (Structural Tools)". EPRI TR-114881 has been superceded by EPRI 1002950, "Aging Effects for Structures and Structural Components (Structural Tools), Revision 1", May 2003. This report discusses the three stressors: (1) Ultraviolet, (2) Thermal, and (3) Radiation listed below.

(1) Ultraviolet: The Structural Tools state "Rubber is decomposed by exposure to ultraviolet radiation. Ultraviolet radiation sources at nuclear plants include solar radiation and ultraviolet or fluorescent lamps. The deterioration of rubber is greatly accelerated in the presence of oxygen. Cracking and checking (splitting), which may occur when rubber is exposed to air and sunlight, are due mainly to reaction with ozone." None of the elastomers in the scope of license renewal at MNGP are exposed to solar radiation. EPRI Report NP-6408, Section 4.3.2, states that UV on elastomers caused by artificial light is of little concern since the amount of UV is very small. For conservatism, MNGP took the position that any

elastomers in close proximity to fluorescent lamps would be managed for aging, however none were found. Therefore, given the absence of solar radiation and the negligible effects from artificial light, these elastomers are not susceptible to hardening and loss of strength, which could be caused by the ultraviolet radiation exposure.

(2) Thermal: The Structural Tools state, "In general, if the ambient temperature is less than about 95 °F, then thermal aging may be considered not significant for the period of extended operation". Since these elastomers are not exposed to temperatures >95 degrees F, they are therefore not susceptible to hardening and loss of strength caused by thermal exposure.

(3) Radiation: The Structural Tools state, "Material property changes and cracking owing to radiation is an applicable aging effect for rubber, neoprene, and silicone elastomers in environments where the radiation exceeds the limits defined above." The limit listed for Rubber is 10^7 Rads, Butyl Rubber 10^6 Rads, and Neoprene 10^6 Rads. Since these elastomers are not exposed to this degree of ionizing radiation exposure, which is orders of magnitude above that corresponding to 60 years of normal plant operation, they are therefore not susceptible to hardening and loss of strength caused by radiation.

EPRI 1002950, "Structural Tools," reviewed industry failure data and NRC generic communications to determine if there was any additional aging effects that should be considered for elastomers. The review did not uncover any new aging effects.

EPRI Report 1007933, "Aging Assessment Field Guide," December 2003, pages 60 through 65, lists degradation mechanisms brought on by the stressors: Thermal, Radiation, and Ultraviolet. Since these elastomers are not exposed to ultraviolet, radiation, or temperatures >95 degrees F, they are therefore not susceptible to hardening and loss of strength and therefore no aging management is required.

Consistent with the above discussion, Monticello only included elastomers in an aging management program that are subject to elevated temperature, ultraviolet, or ionizing radiation. Elastomers are included in the One-Time Inspection Program to confirm that unacceptable degradation has not occurred such that they will perform their intended function during the period of extended operation. If inspections of these more severe applications identify unacceptable degradation, the inspection scope would be expanded as required by the One-Time Inspection Program. The expanded scope would include less environmentally severe applications and could eventually include the elastomers that were excluded from aging management as described above. Therefore, elastomers not explicitly identified as requiring aging management, based on industry experience and technical research, are subject to the One-Time Inspection Program requirements concerning scope expansion and could be inspected if needed based on the examination results of more severe applications.

H. **NRC RAI 3.3.2.3-4**

Tables 3.3.2-3, 3.3.2-5, 3.3.2-6, 3.3.2-7, and 3.3.2-16 identify no aging effects for rubber expansion joints, piping and fittings, and elastomer ventilation seals in a plant indoor air environment. Previously, the staff has identified hardening and loss of strength as aging effects for rubber and elastomer components in this environment and recommended a plant-specific program to manage these aging effects. The plant-specific program should provide periodic inspections of the components to manage these aging effects. The applicant is requested to identify an aging management program to manage hardening and loss of strength for these rubber and elastomer components located in a plant indoor air environment, or provide the technical basis for why these aging effects are not applicable to MNGP.

NMC Response

See NMC response to RAI 3.3.2.3-3.

I. **NRC RAI 3.3.2.3-5**

Tables 3.3.2-5 and 3.3.2-17 identify no aging effects for rubber accumulators, piping and fittings in a treated water environment. Previously, the staff has identified hardening and loss of strength as aging effects for rubber and elastomer components in this environment and recommended a plant-specific program to manage these aging effects. The plant-specific program should provide periodic inspections of the components to manage these aging effects. The applicant is requested to identify an aging management program to manage hardening and loss of strength for these rubber components located in a treated water environment, or provide the technical basis for why these aging effects are not applicable to MNGP.

NMC Response

See NMC response to RAI 3.3.2.3-3.

J. **NRC RAI 3.3.2.3-6**

Tables 3.3.2-6 and 3.3.2-7 identify no aging effects for rubber ventilation seals, piping and fittings in a gas and air internal environment. Previously, the staff has identified hardening and loss of strength as aging effects for rubber and elastomer components in this environment where the internal temperature exceeds 95 °F and recommends a plant-specific program to manage these aging effects. The plant-specific program should provide periodic inspections of the components to manage these aging effects. The applicant is requested to identify an aging management program to manage hardening and loss of strength for these rubber components located in a gas and air internal environment where the internal temperature exceeds 95 °F.

NMC Response

See NMC response to RAI 3.3.2.3-3.

K. NRC RAI 3.3.2.3-7

Tables 3.3.2-6 and 3.3.2-9 identify no aging effects for stainless steel fasteners/bolting and copper alloy flame arresters in an environment exposed to weather. Previously, the staff has identified loss of material due to pitting and crevice corrosion as aging effects for stainless steel and copper alloy components in this environment and recommended a plant-specific program to manage these aging effects. The plant-specific program should provide inspections of the components to manage these aging effects. The applicant is requested to identify an Aging Management Program to manage loss of material due to pitting and crevice corrosion for these stainless steel and copper alloy components located in an environment exposed to weather, or provide the technical basis for why these aging effects are not applicable to MNGP.

NMC Response

Table 3.3.2-6, Emergency Diesel Generators System (EDG) and Table 3.3.2-9, Fire System (FIR) identify stainless steel fasteners/bolting (EDG and FIR), copper alloy flame arrestors (EDG and FIR) and hose house supply valves (FIR) exposed to weather for these Auxiliary Systems. The NMC materials science position, which is in accordance with EPRI 1003056 (Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 3), is that these components do not have a surface exposed to an aggressive chemical species, do not have the potential for concentrating contaminants and are not subject to wetting other than their normal environment. Therefore, loss of material due to crevice or pitting corrosion is not a potential aging mechanism.

Crevice corrosion is a potential aging mechanism for wetted stainless steel and high zinc copper alloys under certain conditions. Crevice corrosion is strongly dependent on the presence of dissolved oxygen. Although oxygen depletion in crevices may occur as a result of the corrosion process, oxygen is still required for the onset of corrosion, and a bulk fluid oxygen content or the presence of contaminants such as chlorides is necessary for the continued dissolution of material in the crevice. For systems with extremely low oxygen content (<0.1 ppm), crevice corrosion is considered insignificant. This form of corrosion requires a crevice where contaminants and corrosion products can concentrate. In addition to oxygen, moisture is required for the mechanism to operate.

Alternate wetting and drying is particularly harmful as this leads to a concentration of atmospheric pollutants and contaminants if they are present. These conditions do not exist at the MNGP.

Pitting corrosion is a potential aging mechanism for wetted stainless steel and high zinc copper alloys under certain conditions. Unless cupric, ferric or mercuric halides are present in the environment, oxygen is required for pitting initiation. Areas where aggressive species can concentrate are particularly susceptible to pitting. Most pitting is the result of halide contamination, with chlorides, bromides, and hypochlorites being prevalent. Pitting is a significant aging effect for stainless steels and high zinc copper alloys when exposed to a corrosive environment. Any continuously wetted or alternately wetted and dried surfaces tend to concentrate aggressive species if they are present and are prone to pitting corrosion. These conditions also do not exist at the MNGP.

For conservatism, the stainless steel fastener/bolting component was added as a "global" asset to assure no components, materials or environments were inadvertently omitted during the AMR process. Recent walk downs of both the EDG and FIR Systems revealed there were no stainless steel fasteners/bolting exposed to weather in either of these systems. Additionally, the FIR hose house supply valves reside within the individual hose house metal enclosures. Although these copper alloy valves are subjected to an "Outside Air Protected from Weather" environment, they were conservatively assigned to the "Exposed to Weather" environment. Sheltered environments tend to preclude the presence of sufficient moisture to promote significant corrosion. Lastly, the copper alloy flame arrestors, though painted (no credit is taken for coatings at MNGP with respect to the mechanical systems), were confirmed to be aluminum during these walk downs. Since aluminum and copper alloys are analyzed essentially in the same manner for loss of material due to crevice and pitting corrosion in an "exposed to weather" external environment, the difference in actual material is considered inconsequential. However, both the EDG and FIR Systems' stainless steel fasteners/bolting exposed to weather asset shall be removed from Table 3.3.2-6 and Table 3.3.2-9 and the material for the flame arrestors shall be changed from copper alloy to aluminum in Table 3.3.2-6.

Since none of these components have a surface exposed to an aggressive chemical species (sulfur dioxide, chlorine gases, sulfur gases, ozone, etc.), do not have the potential for concentrating contaminants and are not subject to wetting other than their normal environment, loss of material due to crevice or pitting corrosion is not a potential aging mechanism. This has been confirmed by system walk downs and substantiated by plant-specific operating experience.

3.4 Steam and Power Conversion System

L. NRC RAI 3.4-1

In Table 3.4.2-2 of the LRA, the applicant has identified no aging effects requiring management for rubber expansion joints intended to maintain the pressure boundary function in a plant indoor air environment. The applicant states that neither the components, nor the material and environment combination are evaluated in NUREG-1801. The applicant further states that these elastomer components (neoprene, rubber, etc.) are indoors and not subject to ultra-violet rays or ozone, nor are they in locations that are subject to radiation exposure. These locations are also not subject to temperatures where changes in material properties or cracking could occur (>95 °F). Therefore, the applicant contends that no aging management is required.

However, it is industry experience that elastomeric expansion joints degrade due to oxidation in environments that are not necessarily harsh, as discussed in EPRI Report 1008035, "Expansion Joint Maintenance Guide," Revision 1, May 2003, and EPRI Report 1007933, "Aging Assessment Field Guide," December 2003. The staff therefore requests the applicant discuss their inspection procedures for the rubber expansion joints related to preventive maintenance both for external and internal surfaces of the elastomer.

NMC Response

EPRI Report 1008035, "Expansion Joint Maintenance Guide", Revision 1, May 2003, Table 5-4, rates elastomers against oxidation, tensile strength, and radiation. Elastomers, such as Neoprene, Natural Rubber, Chlorobutyl, Buna-N, Viton, and EPDM, are rated as good or better in the categories of oxidation, tensile strength, and radiation.

EPRI Report 1007933 "Aging Assessment Field Guide," December 2003, pages 60 through 65, lists oxidation as a degradation mechanism brought on by the stressors: Thermal, Radiation, and Ultraviolet. As stated in the first paragraph of the question, these elastomers are not exposed to these stressors.

Since these elastomers are not exposed to ultraviolet, radiation, or temperatures >95 degrees F, they are therefore not susceptible to oxidation and no aging management is required.

Also, see related response to RAI 3.3.2.3-3.

M. NRC RAI 3.4-2

In Table 3.4.2-3 of the LRA, the applicant has identified the aging effects of changes in material properties and cracking due to irradiation and thermal exposure for rubber expansion joints in an internal steam environment. The intended function of the expansion joints is to maintain holdup of radioactive material. The applicant states that neither the components nor the material and environment combination are evaluated in NUREG-1801. The applicant further states that the aging effect/mechanism is applicable, but does not require management since the intended function for this component is post-accident iodine plate-out and hold-up. According to the applicant, main condenser structural integrity is continuously demonstrated during normal plant operation, thus, the intended function is maintained. However, the staff position is that since this component type (rubber expansion joint) is within the scope of license renewal, its aging effects should be managed. Therefore, the applicant is requested to provide the appropriate Aging Management Program to manage the aging effect of changes in material properties and cracking due to irradiation and thermal expansion of the rubber expansion joints in a steam environment.

NMC Response

For both a Loss of Coolant Accident (LOCA) and a Control Rod Drop Accident (CRDA), radioactive iodine is assumed to be held up and plate-out on the interior surfaces of the main condenser. "Plate-out and holdup of radioactive material" is the only intended function assigned to the main condenser expansion joints.

Aging management is not required for the main condenser components that have only a plate-out and holdup of radioactive material intended function. For these components, the aging effects do not require aging management because the deposition of iodine in the main condenser is unaffected by the condenser surface condition. To maintain the intended function, the main condenser and the components, which make up the main condenser complex, simply have to remain intact.

Condenser structural integrity is continuously demonstrated during normal operation when the condenser is required to maintain vacuum. Following a design basis accident, when the condenser is required to perform its intended function, the main steam isolation valves will be closed and vacuum will be lost. The condenser will not be required to perform a pressure boundary function because atmospheric conditions will exist inside the condenser.

Since normal performance considerations such as fouling and in-leakage (e.g., circulating water or air leaks) place greater requirements on condenser operation than the post-accident plate-out, then as long as the condenser is intact and operational, the post-accident plate-out and holdup of radioactive material intended function will be maintained and no aging management is required.

4.9 Reactor Building Crane Load Cycles

N. NRC RAI 4.9-1

In Section 4.9 of the LRA related to the reactor building crane load cycles TLAA [Time Limited Aging Analysis], the applicant contends that the current analysis of the fatigue life remains valid for the 60 year extended operating period. It is the staff's understanding that this crane will also handle spent fuel pool shipping casks. A refueling service platform with handling and grappling fixtures services the refueling area and the spent fuel pool. The applicant is requested to provide a fatigue analysis associated with lifts of the spent fuel casks and explain how the heavy load fatigue analysis provided in Section 4.9 of the LRA is the governing analysis for the TLAA.

NMC Response

Section 4.9 of the LRA accounted for cycles due to anticipated lifts of spent fuel casks by the addition of heavy lift cycles. The current analysis conservatively assumed 1,120 cycles (for 40 years of operation) due to lifts of reactor building shield blocks and plugs, the reactor vessel head, the drywell vessel head, the steam separator assembly, and the steam dryer assembly. The difference between 1,120 to 2,000 cycles identified in Section 4.9 includes consideration of additional spent fuel cask lifts, as well as additional current design basis lifts attributable to the license renewal period of extended operation.

The reactor building crane is currently being upgraded from 85 tons to 105 tons in anticipation of spent fuel cask duty. Crane calculations are being performed in accordance with CMAA 70-1975, which identifies stress ranges and allowable cycles. Preliminary calculations demonstrate that the maximum stress range for the upgrade design is less than the allowable stress range for the most severe crane classification operating up to 100,000 cycles. The remaining crane components are being designed with a 5:1 safety factor, which assures that the fatigue threshold for 100,000 cycles will not be exceeded. Assuming that offloading of fuel to a spent fuel storage facility must begin with the next refueling outage at a rate equal to fuel replenishments, as well as spent fuel pool offloading due to decommissioning activities, the total number of additional cycles is not expected to exceed 120. This includes the conservative consideration that both cask placement for acceptance of spent fuel and removal of the loaded cask to the spent fuel transfer vehicle are at fully loaded conditions. This results in a total number of cycles, at maximum load for 60 years of operation, of 1,800 out of 70,000 allowable cycles identified in the LRA.

The crane upgrade calculations have not been completed. Upon completion of the modification analysis, an evaluation will be made to determine the effect, if any, on Section 4.9. If the results are not bounded by the current LRA evaluation/disposition a revised Section 4.9 will be included with the first Annual LRA Supplement required by 10 CFR Part 54, § 54.21(b).

B2.1.4 Bolting Integrity Program

O. NRC RAI B2.1.4-1

Table Item Numbers 3.3.1-18, 3.3.1-24 and 3.4.1-08 in the LRA provide a general discussion of the Bolting Integrity Program as applied to the ESF, auxiliary and SPC systems. The discussion section for each system states that while loss of preload is not specifically identified as an aging effect in the respective AMR table, it is managed for carbon steel and stainless steel closure bolting used in pressure retaining joints by the Bolting Integrity Program through periodic inspections, material selection, thread lubrication control, assembly and torque requirements, and repair and replacement activities. Based on this discussion, the staff considers closure bolting in the ESF, auxiliary and SPC systems to be managed for loss of preload by the Bolting Integrity Program. The applicant is requested to discuss whether all closure bolting in the ESF, auxiliary and SPC systems is managed for loss of preload by the Bolting Integrity Program although the AMR tables do not contain specific line items for this aging effect.

NMC Response

As discussed in Section B2.1.4 of the License Renewal Application, the Bolting Integrity Program manages aging effects for bolting within the scope of license renewal. This includes closure bolting that is required to support a pressure boundary intended function for components of the systems listed in Section B2.1.4, Scope of Program. Detection of aging effects includes visual inspection of pressure retaining joints for signs of leakage, which may be the result of loss of preload. With the exception of the Emergency Filtration (EFT) System, this includes all closure bolting of the Engineered Safety Features (ESF), Auxiliary, and Steam and Power Conversion (SPC) systems in the LRA. As noted in LRA Table 3.3.2-7, bolting of the EFT System is not susceptible to aging effects due to is location in a controlled environment and is, therefore, not included in the Bolting Integrity Program.

P. NRC RAI B2.1.4-2

The LRA states that the Primary Containment In-Service Inspection Program provides for visual examination of accessible surfaces of drywell, torus, etc. Recent experience with failed bolts on T-quencher supports at Hatch Nuclear Plant Unit 2 has shown that high strength bolts are susceptible to hydrogen induced cracking and may fail after 20 to 25 years of service. In order to assess the adequacy of Monticello's Bolting Integrity Program, please provide the following information:

Has the applicant and/or his contractor reviewed the Hatch 2 bolt failure event for applicability to Monticello?

If yes, what are the results from that review? Why does the applicant believe that this event cannot take place at Monticello?

If no, when is the applicant planning to complete the review? Why does the applicant believe that this event is not applicable to its facility?

NMC Response

The Hatch 2 bolt failure event was distributed as industry operating experience by the Institute of Nuclear Power Operations (INPO). The event was included in the MNGP Operating Experience Program and the evaluation is in progress. Preliminary results indicate this event is not applicable to the MNGP for the following reasons:

1. The tee-quencher support design at the MNGP is different. A support beam with welded plates and gussets at each end is used to support the entire length of the quencher. Bolted brackets are used at six locations for each tee quencher (four bolts at each bracket) to mount and support the tee quencher on top of the beam. Three of the tee quenchers were installed in September 1977 and the remaining five were installed in November 1978.

2. All bolts are 1-inch diameter, 3.75-inch long hex bolts comprised of ASTM A-325 Type 1 or A-193 Grade B7 according to the material specification. These are not high strength bolts; the ultimate stress is approximately 125 ksi or less and well below the ultimate stress of SA540 Grade B21 Class 1 bolts used at Hatch 2. Consistent with the MNGP LRA and operating experience review, stress corrosion cracking is only a concern in high strength bolts.

3. Analysis of the Hatch 2 event determined the most likely cause as stress corrosion cracking of high strength bolts with a likely significant contribution of Hydrogen embrittlement. One possible source of the hydrogen embrittlement is use of a zinc primer inside the torus. The MNGP does not use a zinc primer and, instead, uses a modified phenolic based primer.

4. Finally, underwater inspections of these bolts are performed on a periodic basis. Inspections performed in May 1993 identified no problems or loose connections.

Q. NRC RAI B2.1.4-3

Does the Primary Containment In-Service Inspection Program include requirements for diver's inspection of underwater bolting in the Torus? If not, why not?

NMC Response

Yes, the MNGP Primary Containment In-Service Inspection Program includes activities that perform periodic visual inspections by divers (when the torus is not drained) and by engineers (when drained) for below water-line components including their support members, bolted connections, and welds. Components inspected include such items as the T-quenchers, SRV piping and supports, emergency core cooling system strainers, vent header supports, catwalk supports, and other submerged piping and supports not included in the IWE, VT-3 inspection. Inspections are conducted periodically at intervals not to exceed five years. The MNGP Primary Containment In-Service Inspection Program manages aging effects for visible degradation such as deformation, cracks, corrosion, wear, and signs of bolt looseness.

Access to components inside the torus is limited. Since the MNGP Primary Containment In-Service Inspection Program inspects components inside the torus, it is relied upon to manage aging effects for miscellaneous steel components listed above.

B2.1.32 System Condition Monitoring Program

R. NRC RAI B2.1.32-1

The System Condition Monitoring Program in LRA Section B2.1.32 manages aging effects through visual inspection and monitoring of external surfaces for leakage and evidence of material degradation. The AMP does not address how inspection of accessible surfaces will provide reasonable assurance that inaccessible surfaces are managed. The applicant is requested to list any inaccessible surfaces of components (including lagged/insulated piping < 212 °F) that will be managed by this program and discuss the bases for determining that the inaccessible surfaces will be adequately managed.

NMC Response

The System Condition Monitoring Program manages aging effects through visual inspection and monitoring of SSCs that are accessible during normal operation, during refueling outages, or as part of planned maintenance.

Accessible areas are those areas that are available for inspection and monitoring during routine operations or that become accessible for inspection and monitoring during refueling or maintenance activities. Insulated piping can be made accessible, as needed, for inspection and monitoring for the presence of age related degradation of SSCs within the scope of license renewal. For example, insulated piping at operating temperatures >212 degrees F can normally be evaluated for aging effects based on the inspection of uninsulated piping of the same materials in the same environment. Because of this temperature, a wetted environment is not expected. For insulated piping operating <212 degrees F (e.g., HVAC cooling loops), inspections will include removal of insulation where it is determined that inspections of uninsulated portions cannot be extrapolated for managing relevant aging effects.

Visual inspections will be performed of observable indicators that identify the presence of age related degradation. Examples of observable indicators are crack-like indications, corrosion, erosion, leakage, presence of moisture (condensation), or physical displacement.

Inaccessible areas are those areas that have no access due to facility construction (i.e., require a plant modification to access) or that present a significant health, safety, and/or radiological hazard. SSCs that require aging management that are inaccessible will be evaluated for the impact of aging based on comparable accessible locations. This evaluation will be performed on accessible SSCs on the basis of same material(s) and the same or more severe environment(s) as those portions that are considered inaccessible.

If an unacceptable condition or situation is identified in an accessible portion of a system, an extent of condition evaluation will be performed to determine whether the same condition or situation is applicable to other accessible or inaccessible portions of the system. Appropriate follow-up inspection and corrective actions will be implemented as needed.

S. <u>NRC RAI B2.1.32-2</u>

The System Condition Monitoring Program is credited with managing the following aging effects located in various sections of the LRA:

(a) Change in material properties and cracking for neoprene ventilation seals in engineered safety features systems;

(b) Stress cracking corrosion for stainless steel piping and fittings in auxiliary system;

(c) Crevice corrosion for steel and copper alloy components in the auxiliary systems;

(d) Crevice corrosion for copper alloy components in the steam and power conversion systems;

(e) Stress cracking corrosion and crevice corrosion for stainless steel spent fuel pool liner.

It is not apparent how these types of aging effects will be identified during a system walkdown visual inspection. The applicant is requested to discuss the inspection methods and techniques used to detect each of the above aging effects and the acceptance criteria for each aging effect.

NMC Response

The methods and techniques for the detection of the above aging effects will be accomplished in accordance with the recommendations of industry guidelines. Direct visual inspection may be augmented by the use of tools such as, mirrors, binoculars, and flashlights. EPRI documents will be the general source for guidance on aging detection techniques. These guidance documents include field guides and aging identification and assessment checklists. These documents provide descriptions of observable indicators relative to specific aging degradation.

Examples of EPRI guidance documents are:

- TR-107668, "Guidelines for System Monitoring by System Engineers"
- TR-104514, "How to Conduct Material Condition Inspections"
- 1007933, "Aging Assessment Field Guide"

EPRI 1007933 is a field guide for assessing aging degradation. This field guide provides a description of the aging degradation and photographic images of the actual degradation. This field guide has specific indicators to identify aging degradation. For example, the polymers (including neoprene) section lists indicators for chemical, thermal, radiation, ultraviolet, etc. induced degradation. Crevice corrosion is also included under the topic of metal degradation.

Instruction to understand age related degradation of plant SSCs and to identify the leading indicators of various degradation mechanisms and effects will be provided. EPRI guidance, supplemented by other related materials, will be used to establish this instruction. Examples of training topics are:

- Fundamentals
- Metals Aging Degradation
- Concrete Aging Degradation
- Polymers Aging Degradation
- Protective Coatings and Linings Aging Degradation
- Electrical Components Aging Degradation

Should there be indication of an unacceptable degradation, the visual inspection will be supplemented with other examine techniques or analytical evaluation as needed. For example, visual observation of crack-like-indications identified during monitoring will be reported via the corrective action process. As part of the corrective action process, further evaluation will be performed using applicable techniques such as, non-destructive examination methods (e.g., dye penetrant testing), to determine the extent of degradation and needed corrective actions. This process would be used to confirm the presence of stress corrosion cracking.

In response to the specific items in this question, the following information is provided:

Item a

Regarding changes in material condition or cracking in elastomers, including neoprene, visual inspection will detect degradation indicators such as discoloration, surface films, wrinkling, distortion, and crack-like indications. The presence of any of these indicators will trigger an evaluation to determine the extent of degradation.

Item b

Visual inspection will identify crack-like indications that will require further evaluation via the corrective action process. Further evaluation, via NDE methods, will identify the specific type of cracking, such as stress corrosion cracking. See response to RAI 3.3.2.3-1.

Items c and d

Visual inspection will identify loss of material due to corrosion as evidenced by the presence of localized corrosion products, such as scale and metal oxides. The majority of the remaining exposed base metal will appear unaffected. Identification of the corrosion as crevice corrosion is based on locations and materials that would be susceptible to this type of corrosion because of crevice geometry (e.g., presence of crevices or crevice forming materials, bolted versus welded connections) and stagnant liquid environment. Additional guidance (from industry sources such as NACE International) will be used identify crevice corrosion as well other types of corrosion as appropriate. Significant surface degradation will be evaluated via the corrective action process.

Item e

Cracking due to stress corrosion cracking and loss of material due to crevice corrosion for the stainless steel spent fuel pool liner in a treated water environment is managed by the Plant Chemistry Program as stated in LRA Table 3.5.2-15 (Page 3-748). This is consistent with GALL line item III.A5.2-b. However, this same GALL line item further states under the Aging Effect/Mechanism column "...and monitoring of the spent fuel pool water level." Monitoring of the spent fuel pool water level is not an element of the Plant Chemistry Program but rather of the System Condition Monitoring Program.

As a result, the System Condition Monitoring Program is also credited in LRA Table 3.5.2-15 for monitoring of the spent fuel pool water level that is also consistent with GALL line item III.A5.2-b. Additionally, Note 539 states, "The System Condition Monitoring Program is credited for monitoring the spent fuel pool water level and spent fuel pool leakage". This note was specifically added to define the consistency with GALL and to differentiate between the two AMPs with regard to what aging effect/mechanism was managed by each.

Consequently, the Plant Chemistry Program specifically manages stress corrosion cracking and the System Monitoring Program specifically manages monitoring of the spent fuel pool water level IAW GALL line item III.A5.2-b.