UNITED STATES
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May 17, 2001

MEMORANDUM TO: File

FROM: Sikhindra K. Mitra, Project Manager
License Renewal and Standardization Branch
Division of Regulatory Improvement Programs, NRR

SUBJECT: NUCLEAR ENERGY INSTITUTE (NEI) ELECTRONIC SUBMITTAL OF ADDITIONAL SAMPLES FOR THE LICENSE RENEWAL DEMONSTRATION PROJECT

On May 10, 2001, Mr. Allen Nelson, Senior Project Manager, Licensing, NEI, electronically submitted attached documents as samples for license renewal demonstration project as a result of a conference call with the staff on May 3, 2001. NEI was committed to provide the two approaches of the samples, one in a SRP format and the other in a six column table format. But due to the industry workloads, NEI provided only the SRP format with this submittal.. The samples which was provided this time also lacked sufficient detail and alignment for the staff to write a meaningful safety evaluation (SE). In a discussion with Mr. Nelson on May11, 2001, and a telephone conversation with Mr. Doug Walters of NEI on May 15, 2001, the staff conveyed to NEI that these samples could not be used for writing SE. NEI agreed to submit the complete repackaged samples again by May 18, 2001.

Project No. 690

Attachment : As stated

Appendix B Program Descriptions And FSAR Sections

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From: "NELSON, Alan" <apn@nei.org>
To: "'S K Mitra'" <skm1@nrc.gov>
Date: 5/10/01 12:22PM
Subject: Demonstration material

S.K.:

On May 1st the NEI License Renewal Implementation Guideline Task Force met with the NRC License Renewal staff at NRC White Flint offices. The Class of 2002 is engaged in an effort to demonstrate how Gall and the standard review plan will be used in a license renewal application. The purpose of the meeting was to present and discuss two developed approaches. Based on the discussion of May 1st and a follow-up conference call May 3rd with the staff we have repackaged the attached example approaches for your review.

In an effort to determine which approach would optimize industry preparation and NRC staff review please consider the following:

* Does the staff prefer one approach to the other and will one approach be more "review efficient"?
* A determination needs to be made if programs that are evaluated in GALL can be applied to non- GALL evaluated components?

We committed to provide the two approaches by May 11th, but due to industry workloads we are able to provide one approach at this time. We will make best efforts to provide the five column approach in a about week. As discussed we thought it best that if the staff could begin their review with this approach.

The attach is a single file which includes Sections 2, 3 for Steam and Power Conversion, Structural and Electrical areas. This file also includes a set of programs in the three possible types identified as
1. Consistent with GALL
2. Consistent with GALL with exceptions
3. Plant Specific Programs
The program set was not designed to match up with the credited programs in Section 3 it was designed to present the potential format and level of detail to be included in this type of presentation for Appendix B.
Please note that the GALL Program references are all based upon the August 2000 draft. The order and numbering scheme for the program sections are consistent with NUREG 1801. Please note there is no page 3.4-10.

If you have any questions, please call me at (202) 739- 8110.

Alan Nelson

<<SRP-LR format Appendix B.doc>> <<SRP-LR format Section 2.doc>> <<SRP-LR format Section 3 .doc>>

CC: "'Chris Grimes'" <cig@nrc.gov>, "'P T Kuo'" <ptk@nrc.gov>, "HENDRICKS, Lynnette" <lxh@nei.org>, "WALTERS, Doug" <djw@nei.org>

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Appendix B Program Descriptions And FSAR Sections

Consistent With GALL

FLOW ACCELERATED CORROSION PROGRAM

The Flow Accelerated Corrosion (FAC) Program is credited for aging management of selected piping and components in the following systems:

Main Steam System
Feedwater System
Steam Generator Blowdown System

The Flow Accelerated Corrosion (FAC) Program is consistent with the ten attributes of aging management program XI.M6, Flow Accelerated Corrosion, specified in GALL (August 2000 – DRAFT) Chapter XI.

Operating Experience:

Various sections of the Main Steam, Feedwater, and Blowdown system piping are periodically examined using nondestructive examination to determine the effects of flow accelerated corrosion. Indications of FAC are evaluated and piping may be either repaired or replaced if sufficient wall thinning is identified.

Ultrasonic examinations have identified pipe wall thinning below established screening criteria. On occasion, visual observations have identified through wall erosion on piping components. These deficiencies were documented in accordance with the corrective action program and resulted in repair or replacement of the marginal areas.

A rupture occurred on an auxiliary steam line in 1997 that resulted in significant upgrades to the FAC program to bring it up to current industry standards. Internal audits of the program since the 1997 event show the program has been maintained in accordance with NSAC–202L–R2 .

Based on the program enhancements which have been implemented, the continued implementation of the Flow Accelerated Corrosion (FAC) Program provides reasonable assurance that the aging effects of flow accelerated corrosion will be managed such that Main Steam, Feedwater, and Blowdown system components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

FSAR Revision:

The Flow Accelerated Corrosion (FAC) program manages the aging effects of wall loss due to FAC for the Main Steam, Feedwater, and Blowdown Systems. The FAC program relies primarily on monitoring and inspection of piping/components to preclude failure of high and low energy carbon steel piping. The Program Basis Document for FAC clearly defines the actions, procedures and steps required to prevent primary pressure boundary failure of the piping/components in scope. All inspection locations must satisfy specified evaluation criteria in order for a component to remain in service.

The program will be enhanced to address valve body erosion by visual inspections prior to the end of the initial operating license terms for Plant X.

STRUCTURES MONITORING PROGRAM

As identified in Chapter 3, the Structures Monitoring Program is credited for aging management of specific component groups in the following structures:

Auxiliary Building	Containment
Intake Structure	Turbine Building

The Structures Monitoring Program is credited for managing the effects of Loss of Material for selected structures within the scope of license renewal. The program provides for visual inspection and examination of accessible surfaces of specific structures and components, including welds and bolting.

Aging management of structural components that are inaccessible for inspection is accomplished by inspecting accessible structural components with similar materials and environments for aging effects that may be indicative of aging effects for inaccessible structural components.

With identified enhancements, the Structures Monitoring Programs is consistent with the ten attributes identified in the NRC GALL Report (August 2000 DRAFT) for Structures Monitoring Program XI.S6.

Operating Experience

Inspections have been performed in the Auxiliary Building, Containment, Intake Structure, and Turbine Building in 1996/1997 and 1999/2000. No significant deterioration has been identified in the inspections performed.

FSAR Revision

The Structures Monitoring Program manages the aging effect of loss of material. The program provides for periodic visual inspection and examination for degradation of accessible surfaces in designated structures that fall within the scope of license renewal.

PRIMARY CHEMISTRY MONITORING PROGRAM

The Primary Chemistry Monitoring Program is credited for managing the aging affects applicable to the passive component/item groupings exposed to contact with the reactor coolant. The concentration of chemical impurities and chemical additions are controlled through monitoring requirements and compliance with specifications which contain chemistry limits. Section 3 of this LRA provides matrices of the affected components/item groupings and the aging effects mitigated by the monitoring program. The Primary Chemistry Monitoring Program is consistent with the ten criteria of aging management program XI.M11, Water Chemistry, specified in GALL (August 2000 – DRAFT) Chapter XI.

Operating Experience and Demonstation

Operating experience on the primary systems demonstrates the effectiveness of the Primary Water Chemistry Monitoring program. No significant chemistry related degradation for primary components/item groupings has been experienced. Experience has shown that implementation of a primary chemistry program in accordance with accepted industry standards is effective in managing the effects of aging. Based on this experience, the continued implementation of the Primary Chemistry Monitoring program provides reasonable assurance that aging effects will be managed so that primary system components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

FSAR Revison

The Primary Chemistry Monitoring Program maximizes long-term availability of primary systems by minimizing system corrosion, fuel corrosion, and radiation field build-up. The scope of the Primary Chemistry Monitoring Program includes sampling activities and analysis on the following systems: RCS, borated water storage tanks, spent fuel pool system, letdown purification demineralizers, and reactor makeup water. The Primary Chemistry Monitoring Program provides assurance that an elevated level of contaminants and oxygen does not exist in the systems covered by the program. This prevents or minimizes the occurrence of cracking and other aging effects.

OUTER SURFACES OF ABOVE GROUND CARBON STEEL TANKS INSPECTION PROGRAM

GALL (August 2000 – DRAFT) Chapter XI, program XI.M7, Outer Surfaces of Above Ground Carbon Steel Tanks, includes preventative measures to mitigate corrosion by inspecting the external surface of carbon steel tanks with paint or coatings in accordance with standard industry practice. These GALL program recommendations are implemented by the Preventative Maintenance Inspection Program requirements. Section 3 of this LRA provides matrices of the affected components/item groupings and the aging effects mitigated by the monitoring program. The Preventative Maintenance Program is consistent with the ten attributes of an aging management program for XI.M7, Outer Surfaces of Above Ground Carbon Steel Tanks, specified in GALL (August 2000 – DRAFT) Chapter XI.

Operating Experience and Demonstration

Operating experience has shown that protective coatings utilized during the construction and maintenance of are effective barriers to mitigate corrosion. Visual inspections will continue to be performed and corrective actions will be initiated when necessary. No unacceptable indications of cracking, loss of material, and change in material properties is allowed to go uncorrected. Based on this experience, the continued implementation of the Preventative Maintenace Program provides reasonable assurance that aging effects will be managed so that Above Ground Carbon Steel Tanks will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

FSAR Revision

(*not mandatory since the GALL Program description is implemented by the Preventative Maintenance Program*)

Outer Surfaces of Above Ground Carbon Steel Tanks Inspection Program

Inspections of Outer Surfaces of Above Ground Carbon Steel Tanks will continue to be performed to ensure that a loss of material due to external surface corrosion of these tanks is adequately managed. The inspection requirements implemented by the Preventative Maintenance Program bound the inspection requirements identified by GALL. XI.M7, Outer Surfaces of Above Ground Carbon Steel Tanks. These inspections will continue for the period of extended operation.

CONTAINMENT INSERVICE INSPECTION PROGRAM

As identified in Chapter 3, the Plant X Containment Inservice Inspection Program, which includes the examination requirements needed to comply with both ASME Section XI, Subsection IWE and Subsection IWL, is credited for the aging management of specific structural component/commodity groups, including the post-tensioning system, for the Containment Structure.

As background, the NRC amended 10 CFR §50.55a to incorporate by reference the ASME Boiler and Pressure Vessel Code, Section XI Subsections IWE and IWL 1992 Edition with the 1992 Addenda, with specified modifications and limitations.

The 10 Year Containment (IWE & IWL) Inservice Inspection Program Plan and Basis for Plant X, incorporating Subsection IWE and Subsection IWL examination requirements is currently under development to meet the expedited examination date of September 9, 2001.

The Plant X Containment Inservice Inspection Program effectively manages the aging effects identified in Section 3.5 of this application and is consistent with GALL Chapter XI.S1 "ASME Section XI, Subsection IWE, and Chapter XI.S2, " ASME Section XI, Subsection IWL" as identified in the Draft - August 2000 version of the GALL, with the following clarifications:

For Examination Category E-D Inspection components, a Request for Relief (IWE-001) has been requested for the Visual VT-3 examination requirements.

For Examination Category E-A Inspection requirements, a Request for Relief (IWE-006) has been requested for the requisite Visual VT-3 examinations.

A Request for Relief (IWE-003) has been requested for the specific requirement of re-examining areas of degradation or repairs during the next inspection period, in accordance with Examination Category E-C.

As discussed in Section 3.5 of this application there are no aging effects requiring management related to the concrete portion of the containment structure.

OPERATING EXPERIENCE AND DEMONSTRATION

The past inspections of the Containment Liner have been conducted in accordance with the Containment Leak Rate Testing Program and the Maintenance Rule Implementation Program. The inspections performed under these programs were previously documented and evaluated for any degraded conditions associated with the containment liner.

Previous inspections of the tendons and tendon anchorages were conducted in accordance with Technical Specifications, the USAR, and plant procedures. The inspections performed under these programs documented and evaluated any degraded conditions associated with the post-tensioning system. The ASME Section XI, Subsection IWL Inservice Inspection Program incorporates all of the inspection criteria and guidelines of the previous tendon inspection program attributes and is implemented using existing plant procedures.

The containment tendon examination program has been conducted since initial unit startup at 5-year intervals. The containment tendon surveillance examination requirements incorporated the general criteria and requirements of Regulatory Guide 1.35, "Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containments".

No significant age related deterioration has been identified in the inspections performed.

Appendix B Program Descriptions
And FSAR Sections

Consistent With GALL With Exceptions

EXTERNAL TANK INSPECTION

SYSTEMS AND STRUCTURES MONITORING PROGRAM

The Plant X System and Structures Monitoring Program includes the GALL Outer Surfaces of Above Ground Carbon Steel Tanks (GALL Chapter XI, Program XI.M7). The Systems and Structures Monitoring Program manages the aging effects of loss of material, cracking, fouling, loss of seal, and change in material properties for selected systems, structures, and components (including above ground carbon steel tanks) within the scope of license renewal. The program provides for visual inspection and examination of accessible surfaces. The Systems and Structures Monitoring Program, except as noted below, is consistent with the ten attributes of an aging management program for GALL XI.M7, Outer Surfaces of Above Ground Carbon Steel Tanks.

Exceptions To Gall Requirements

Carbon steel tanks are coated to minimize corrosion. Coatings minimize corrosion by limiting exposure to the environment. However, no credit has been taken by Plant X for coatings in the determination of aging effects requiring management. Coatings are thus not required to ensure that license renewal intended functions will be maintained for the period of extended operation.

Operating Experience And Demonstration

Material condition inspections have been successfully performed at Plant X since the mid-1980s. The inspection requirements in support of the Maintenance Rule (10 CFR 50.65) have been in effect since 1996 and have proven effective at maintaining systems/structures material condition and detecting unsatisfactory conditions that have resulted in effective corrective actions being taken.

The Systems and Structures Monitoring Program has been an ongoing program at Plant X and has been enhanced over the years to include the best practices recommended by the Institute for Nuclear Power Operations (INPO) and other industry guidance. Additionally, the Systems and Structures Monitoring Program will continue to support implementation of the NRC Maintenance Rule.

The effectiveness of the Systems and Structures Monitoring Program is supported by the improved material conditions, documented by internal as well as external assessments of the last several years. The Systems and Structures Monitoring Program is the subject of periodic internal and external assessments to insure continued effectiveness and improvement.

Based upon the above, the continued implementation of the Systems and Structures Monitoring Program provides reasonable assurance that the aging effects requiring management will be managed such that systems and structures within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

PRIMARY CHEMISTRY MONITORING PROGRAM

The Primary Chemistry Monitoring Program is credited for managing the aging affects applicable to the passive component/item groupings exposed to contact with the reactor coolant. The concentration of chemical impurities and chemical additions are controlled through monitoring requirements and compliance with specifications which contain chemistry limits. Section 3 of this LRA provides matrices of the affected components/item groupings and the aging effects mitigated by the monitoring program. The Primary Chemistry Monitoring Program is consistent with the ten attributes of aging management program XI.M11, Water Chemistry, specified in GALL (August 2000 – DRAFT) Chapter XI, except as discussed below.

Exception to GALL Requirements

The program description for Water Chemistry, XI.M11, specified in GALL (August 2000 – DRAFT) Chapter XI, requires a one-time inspection for use in conjunction with existing program requirements to be developed and reviewed on a plant specific basis. [p*lant name*] takes exception to the one-time inspection requirement. Operating experience at [p*lant name*] has not identified any problems that would warrant a one-time inspection to confirm the adequacy of the chemistry programs. This experience includes inspections of systems and components during maintenance activities that occur routinely. [*specific examples would be provided here*] These inspections have not identified aging effects other than those identified in the LRA and the adequacy of the chemistry programs has been confirmed by these maintenance-related inspections.

Operating Experience and Demonstration

Operating experience on the primary systems demonstrates the effectiveness of the Primary Water Chemistry Monitoring program. No significant chemistry related degradation for primary components/item groupings has been experienced. Experience has shown that implementation of a primary chemistry program in accordance with accepted industry standards is effective in managing the effects of aging. Based on this experience, the continued implementation of the Primary Chemistry Monitoring program provides reasonable assurance that aging effects will be managed so that primary system components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

FSAR Revision

The Primary Chemistry Monitoring Program maximizes long-term availability of primary systems by minimizing system corrosion, fuel corrosion, and radiation field build-up. The scope of the Primary Chemistry Monitoring Program includes sampling activities and analysis on the following systems: RCS, borated water storage tanks, spent fuel pool system, letdown purification demineralizers, and reactor makeup water. The Primary Chemistry Monitoring Program provides assurance that an elevated level of contaminants and oxygen does not exist in the systems covered by the program. This prevents or minimizes the occurrence of cracking and other aging effects.

BURIED PIPING MONITORING PROGRAM

The Buried Pipe Monitoring Program, a new program to be initiated prior to expiration of the current license, is credited for managing the aging affects applicable to safety related underground piping in service water and fuel oil systems. This program assures the protective coatings on the underground piping will continue to protect the external surfaces of the piping. Section 3 of this LRA provides matrices of the affected components/item groupings and the aging effects mitigated by the monitoring program. The Buried Pipe Inspection Program is consistent with the ten attributes of an aging management program for XI.M8, Outer Suface of Buried Piping and Components, specified in GALL (August 2000 – DRAFT) Chapter XI, except as discussed below.

Exception to GALL Requirements

[p*lant name*] takes exception to the recommended one year sampling frequency requirement identified in GALL (August 2000 – DRAFT) Chapter XI.M8. The [*plant name*] inspection program does not include scheduled excavation and inspection to meet the sampling frequency since the process for excavation of buried piping for inspection would increase the possibility of damage to the coatings on the buried piping. The Buried Piping Inspection Program will be based on random excavations associated with required maintenance activities, usually to facilitate repairs. These are not scheduled activities. [*specific examples would be provided here*] estimates buried piping will be excavated every five to ten years. Acceptance criteria for integrity of the coatings will be defined in plant procedures. Corrective actions and actions to preclude recurrence of aging effects, if discovered, will be determined in accordance with 10 CFR Part 50, Appendix B, Quality Assurance requirements.

Operating Experience and Demonstration

Operating experience has shown that buried piping coatings are effective barriers to prevent aging. Based on this experience, the continued implementation of the Buried Pipe Monitoring Program provides reasonable assurance that aging effects will be managed so that buried pipes will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

FSAR Revision

Buried Pipe Inspections will be performed to ensure that a loss of material due to externals surface corrosion of buried piping is adequately managed. The safety-related portions of underground carbon steel piping on the service water and fuel oil systems are within the scope of this inspection. The aging effect addressed by the Buried Pipe Inspection is a loss of material due to corrosion of the external surfaces of pipe caused by loss of the protective coating. This inspection will be initiated prior to the end of the initial 40-year license term.

ELECTRICAL COMPONENT INSPECTION PROGRAM

The Electrical Component Inspection Program is credited for managing aging effects that apply to Non-EQ Inaccessible Medium-Voltage Cables, which are exposed to condensation and wetting in inaccessible locations. The Plant X] Electrical Component Inspection Program will use visual inspections of selected samples of the accessible portion of medium voltage cables to detect aging effects for Non-EQ Inaccessible Medium Voltage Cables. The Electrical Component Inspection Program is consistent with the ten attributes of an aging management program for XI.E3, Non-EQ Inaccessible Medium-Voltage Cables, specified in GALL (August 2000 – DRAFT) Chapter XI, except as discussed below.

Exception to GALL Requirements

Plant X takes exception to the recommended ten year testing frequency requirement identified in GALL (August 2000 – DRAFT) Chapter XI.M8. The Plant X inspection program does not include scheduled testing since Plant X has determined that these Non-EQ Inaccessible Medium-Voltage Cables were designed for the applications where they are installed. The moisture and voltage exposures described as significant within the GALL program description are not significant at Plant X since the design criteria for cables used in these applications assures the cables will continue to perform their intended function. Engineering review determined the expected life of these cables extends beyond the extended period of operation.

Operating Experience and Demonstration

Operating experience has shown Non-EQ Inaccessible Medium-Voltage Cables continue to perform their intended function. The operational environments for these cables have not affected their intended function. Based on this experience, implementation of the visual inspection requirments for accessible Non-EQ Medium-Voltage Cables will provide reasonable assurance that aging effects will be managed so that all medium voltage cables will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation. If an uacceptable condition is identified, the current program requires determination of whether the same conditon or situation is applicable to other accessible or inaccessible cables and connections.

FSAR Revision

ELECTRICAL COMPONENT INSPECTION

The Electrical Component Inspection Program will inspect splices, connectors, and cables within the scope of license renewal that are located in areas that may be conducive to accelerated aging. The scope of the inspection program includes cables exposed to elevated temperatures, wet environments, or corrosive chemicals. The scope also includes cables that can experience elevated temperatures due to the current they are carrying, connectors used in impedance-sensitive circuits, and cable splices subject to aging-related stressors. The aging effect for cables and cable splices is a change of material properties, as evidenced by cracking or discoloration of the insulation or by degradation of a tested parameter. The aging effect for connectors in impedance-sensitive circuits is a change of material due to corrosion of connector pins. The Electrical Component Inspection Program will be formally implemented and the first inspection of in-scope cables, splices, and connectors will be completed prior to the expiration of the initial 40-year licensing term.

Appendix B Program Descriptions And FSAR Sections

Plant Specific Programs

FIELD ERECTED TANKS INTERNAL INSPECTION

As discussed in Chapter 3, the Field Erected Tanks Internal Inspection is credited for aging management of field erected tanks in the following systems: Auxiliary Feedwater, Condensate Storage, Feedwater, Blowdown, and Safety Injection

Scope

This is a one-time inspection of the two condensate storage tanks, two refueling water storage tanks, and the shared demineralized water storage tank. The Field Erected Tanks Internal Inspection is credited with managing the aging effect of loss of material due to corrosion of the tanks within the scope. The one-time inspection of selected internal areas, including surface welds, will determine the extent of internal corrosion in the listed tanks. The visual inspection will consist of direct (e.g., divers) or remote (e.g., television cameras, fiber optic scopes, periscopes) means. Commitment dates associated with the implementation of this new program are contained in Appendix A.

Preventive Actions

Internal tank surfaces are coated to reduce corrosion. Coatings minimize corrosion by limiting exposure to the environment. However, coatings are not credited in the determination of the aging effects requiring management.

Parameters Monitored or Inspected

The material condition of the internal surfaces of accessible areas of the tanks will be visually inspected.

Detection of Aging Effects

The presence of corrosion that could lead to loss of material will be determined by visual inspection of the accessible areas of the field erected tanks. Internal surfaces will be examined for evidence of flaking, blistering, peeling, discoloration, pitting, or excessive corrosion.

Monitoring and Trending

As noted above, this is a one-time inspection, therefore, monitoring or trending is not anticipated. Results of the inspection will be evaluated to determine if additional actions are required.

Acceptance Criteria

The results of the one-time inspection will be evaluated. Specific acceptance criteria will be provided in the implementing procedure.

Confirmation Process

Any follow-up inspection required will be based on the evaluation of the inspection results and will be documented in accordance with the corrective action program.

Operating Experience and Demonstration

Visual inspections have been performed at Pant X for several years. This technique has proven successful for identifying material defects on the surface of field erected tanks.
This inspection is a new activity that will use techniques with demonstrated capability and a proven industry record to detect corrosion. This inspection will be performed utilizing approved procedures and qualified personnel.

Based upon the above, the implementation of the Field Erected Tanks Internal Inspection will provide reasonable assurance that loss of material due to corrosion will be managed such that the structures and components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

FSAR Revision

FIELD ERECTED TANKS INTERNAL INSPECTION

A one-time visual inspection to determine the extent of corrosion on the internal surfaces of the field erected tanks for both units -- including the Condensate Storage Tanks, the Demineralized Water Storage Tank, and the Refueling Water Storage Tanks -- will be performed. The results of these inspections will be evaluated to determine the need for additional inspections/programmatic corrective actions. These inspections will be implemented prior to the end of the initial operating license terms for Plant X.

BURIED PIPING INSPECTION PROGRAM

The purpose of the buried pipe inspection program procedure is to assure that the effects of aging of buried piping are being effectively managed for the period of extended operation under current licensing basis design loading conditions. Loss of material is detectable by visual techniques and, based on operating experience, inspection of a sample of buried components provides for detection of aging effects.

The buried pipe program will enable the site to efficiently develop, modify, and execute the decision-making necessary to:

Define what, if any, action is necessary to provide reasonable assurance through the period of extended operation that loss of material does not result in the DFO or AFW buried piping losing the ability to perform their intended function.

Execute the mitigation and/or discovery activities identified as necessary.

Systems:
Auxiliary Feedwater (AFW)
Diesel Fuel Oil (DFO)

Scope

The buried pipe inspection program applies to plant engineering activities involved in inspecting and maintaining the buried sections of piping for the AFW and DFO systems. The buried pipe program could also be used to inspect all metallic buried piping at XXNPP.

Preventive Actions

External surfaces of carbon steel buried pipe are coated and have cathodic protection to minimize corrosion. Although coatings and cathodic protection minimize corrosion by limiting exposure to the environment and reducing the effects of corrosion to the piping, conservatively they are not credited in the determination of the aging effects that require management.

Parameters Monitored or Inspected

This program will consider variations in environmental conditions (including cathodic protection) to select representative samples of the buried piping for inspection to ensure that the pipe coating/wrapping and cathodic protection system are adequately protecting the pipe from external Aging Effects Requiring Management (AERMs).

The parameters monitored should include the cathodic protection system performance, cathodic protection tap settings, monthly voltage and amperage readings, and quarterly cathodic protection potential profile. Plant XX already monitors these parameters in addition to coating damage observed during inspections of buried pipe sections.

Detection of Aging Effects

The aging effect of concern is loss of material, which is detected by visual observation during piping inspections. Areas of pipe where the coating is missing and the soil surrounding the pipe is wet should be carefully examined for evidence of loss of material.

Monitoring and Trending

The AERMs, if present, would be discovered by regular visual inspections of representative piping sections. The approach for identifying corrosion-related aging effects follows:

1) Buried pipe should be inspected when pipe is excavated during other maintenance and in areas with a history of corrosion problems.

2) Selected areas of buried pipe will be inspected during the last five (5) years of the current operating license term.

3) The locations of such inspections are based on previous inspections and such inspections are not done on a regular schedule.

Trending, if needed, is provided by the site corrective action program.

Acceptance Criteria

Plant procedures provide criteria for determining the acceptability of as-found conditions and for initiating the appropriate corrective action. The acceptance criteria and guidance are geared toward avoiding unacceptable degradation that could threaten the component intended functions.

Confirmation Process

Unacceptable inspection and observation results are evaluated and addressed in the site corrective action process. The corrective process calls for follow-up and confirmation steps.

Corrective Action

The system engineer is responsible for coordinating any necessary repairs to the wrapping and coating of exposed buried piping. Repairs shall be made in accordance with Plant XX procedures and specifications.

Repairs will be inspected by a qualified NDE Inspector and an NDE report will be issued.

Administrative Controls

The procedures governing inspections and observations for buried pipe program are included in the population of procedures subject to 10 CFR 50.59 for control of changes.

Operating Experience

On two separate occasions, plant personnel inspected the DFO buried piping and found that the programs in place to mitigate the aging effects are effective. Specifically, in September 1994 the coatings on a 2-inch and a 3-inch pipe were visually inspected and no degradation of the pipe was found. In November 1996 four 25 foot sections of buried DFO lines were inspected, two 6-inch pipes, one 3-inch pipe, and one 2-inch pipe. During excavation, rocks, stone and concrete were removed (the backfill material was not consistent with the specification which required it to be free of sharp and hard objects). The inspections (visual and a high voltage holiday spark test) found holidays in the coating. At these holiday locations the coatings were removed, the pipe cleaned and inspected. All four pipes were found to be in pristine condition. No evidence of pitting or corrosion damage was found in these areas.

Demonstration

Loss of material must be managed for buried pipe because the carbon steel material used in its construction is susceptible. The aggressiveness of this aging effect is particularly dependent on the overall corrosiveness of the environment and the materials of construction.

Long term exposure to a wet environment may result in localized and/or general area materials loss and, if left unmanaged, could eventually result in loss of pressure retaining capability under CLB design loading conditions. Soil resistivity (or conductivity), chloride and sulfate presence, oxygen content and soil aeration, pH, moisture content of the soil and wet/dry cycles, and microbe activity affect these aging.

Damaged protective coatings/wrappings, holidays or disbonded areas in coating/wrapping, and leakage around caulking can allow these aging effects to develop on the exterior surfaces of the pipe and at the interface where the pipes penetrate the concrete walls.

Based on the above, the continued implementation of the existing inspections and observations for signs of degradation on buried pipes and for conditions that can cause degradation provides reasonable assurance that the aging effect, loss of material, will be properly managed. The buried pipe inspection program will manage piping inspections such that certain systems and components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

FSAR Revision

The Buried Pipe Inspection Program

The Buried Pipe Inspection Program manages the aging effect loss of material. The program applies to plant engineering activities involved in inspecting and maintaining the buried sections of piping for the AFW and DFO systems. The program provides for visual observations during piping inspections identifying degradation in pipe coating/wrapping.

GENERAL CORROSION OF EXTERNAL SURFACES FOR LICENSE RENEWAL PROGRAM

The General Corrosion of External Surfaces for License Renewal Program is credited for aging management of specific non-structural components/commodity groups in the following systems:

Systems:
Auxiliary Feedwater (AFW)
Diesel Fuel Oil and Diesel Lube Oil (DFO & DLO)
Main Steam (MS)
Component Cooling Water (CCW)

Scope

The General Corrosion of External Surfaces for License Renewal Program consists of several activities that manage the aging effects of loss of material for selected systems and non-structural components within the scope of license renewal. The program provides for visual inspection and observation of accessible external surfaces of certain carbon and low-alloy steel components, including piping, valves, supports, tanks, and bolting.

Preventive Actions

External surfaces of most carbons steel and cast iron components are coated to minimize corrosion. Although coatings minimize corrosion by limiting exposure to the environment, they are not credited in the determination of the aging effects that require management.

Parameters Monitored or Inspected

Surface conditions of components are monitored through visual observation and inspection to detect signs of external corrosion and to detect conditions that can result in external corrosion, such as fluid leakage.

Detection of Aging Effects

The aging effect of concern is loss of material which is detected by visual observation and inspection of external surfaces for evidence of leaking fluids, significant coating damage, or significant corrosion. Inspection for evidence of leaking fluids also provides indirect monitoring of certain components that are not routinely accessible.

Monitoring and Trending

Various plant personnel including operators and system engineers perform periodic material condition inspections outside containment. These inspections are performed in accordance with approved plant procedures. Evidence of fluid leaks, significant coating damage, or significant corrosion is documented.

Inspections and observations are performed at intervals based on previous inspections and industry experience. Operator rounds occur several times daily and System Engineer walkdowns occur at least quarterly. Inspections inside containment are conducted each refueling outage by a team that includes knowledgeable subject matter experts from Design Engineering and Quality Control. The in-containment inspections for corrosion are part of the containment coatings inspections established in response to Reg Guide 1.54 (1973) and reviewed by NRC under Generic Letter 98-04.

Acceptance Criteria

Plant procedures provide criteria for determining the acceptability of as-found conditions and for initiating the appropriate corrective action. The acceptance criteria and guidance are related to avoiding unacceptable degradation of the component intended functions, and include existence of leakage, presence of corrosion products, coating defects, and the presence of boric acid crystals. Appropriate provisions of NRC and industry guidance are incorporated.

Confirmation Process

Unacceptable inspection and observation results are evaluated and addressed in the site corrective action process.

Corrective Action

The corrective action process provides measures to verify completion and effectiveness of corrective action.

Administrative Controls

The procedures governing inspections and observations for external corrosion are included in the population of site procedures that are subject to systematic control of changes.

Operating Experience

The activities relied on to detect corrosion of accessible carbon and low-alloy steel and cast iron external surfaces and the precursors thereof are a subset of a larger number of inspection activities that result in redundant inspections. The activities credited for license renewal were selected based on their effectiveness as indicated by a review of site corrective action documents.

The activities are elements of established programs that have been ongoing for years. They have been enhanced over the years based on site and industry experience and are relied on to support implementation of Reg Guide 1.54 for coatings inside containment and the Maintenance Rule (10 CFR 50.65). Review of plant records indicates they are effective in detecting loss of material due to corrosion and its precursors for accessible external surfaces. These findings are consistent with the findings of recent internal and external assessments of these activities, such as audits and NRC inspections.

Demonstration

Loss of material due to corrosion of carbon steel, low allow steel, and cast iron is readily observable for accessible external surfaces. The effect is minimal for coated and uncoated components that are not routinely wetted by humidity, condensation, precipitation, spray, or leakage.

Prompt identification and correction of leakage will minimize the effect for accessible and inaccessible components that are potentially exposed to the leakage. Operator rounds occur several times daily and provide discovery and correction of significant corrosion and of conditions that cause it for components in accessible areas. Periodic system engineer walkdowns augment the operator rounds and provide an independent assessment. Refueling interval inspections provide for discovery of corrosion and of conditions that can cause it for components inside containment.

The effectiveness of these inspection and observation activities is supported by the excellent plant material condition and by site records that show high sensitivity to material condition, housekeeping, and to fluid leakage in particular.

Based on the above, the continued implementation of the existing inspections and observations for signs of external corrosion and for conditions that can cause it provide reasonable assurance that loss of material due to corrosion of external surfaces will be managed such that systems and components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

FSAR Revision

General Corrosion of External Surfaces Program

The General Corrosion of External Surfaces for License Renewal Program manages loss of material due to general corrosion of external surfaces of non-structural carbon steel, low alloy steel, and cast iron components that are (1) inside containment or (2) in normally accessible areas outside containment. The program uses systematic inspections and observations to detect corrosion of external surfaces and conditions that can result in corrosion such as damaged coatings and fluid leaks. Inspections and observations include (1) rounds by operators, (2) system engineer walkdowns, and (3) refueling interval inspections inside containment in accordance with Reg Guide 1.54.

TANK INSPECTION PROGRAM

The Tank Inspection Program is credited for aging management of specific non-structural components/commodity groups in the following systems:

System:
Diesel Fuel Oil (DFO)

Scope

The tank inspection program applies to plant engineering activities involved in inspecting and maintaining tank internal materials per XXNPP's license renewal commitments. The XXNPP Tank Internal Inspection Program is intended to provide assurance that the aging effects are being effectively managed.

Preventive Actions

Fuel oil is not corrosive to carbon steel under the normal conditions present in the Fuel Oil Storage Tanks (FOST). Significant rates of corrosion-related Aging Effects Requiring Management (AERM) occur only when water is present with the fuel oil in the tank. While the presence of water in the tank cannot be totally prevented, the amount of water and the length of time it may be present in the tank can be minimized. The minimal amount of water and length of time the water is present is an effective method of mitigating the aging effects. Corrosion inhibitors, if required, are added to new fuel oil to maintain a non-corrosive environment in the tank.

Another method of mitigating the effects of aging on the tank interior is to apply a protective coating, which prevents contact between the metal surfaces of the tank and the system fluid or contaminant fluid. By preventing contact, the AERMs cannot occur. Although coatings minimize corrosion by limiting exposure to the environment and reducing the effects of corrosion to the tank, conservatively they are not credited in the determination of the aging effects that require management.

Parameters Monitored or Inspected

The Diesel FOST Internal Inspection Program will manage the aging effect, loss of material. The inspections will monitor for flaking, blistering, or damaged sections of coating and inspect the welds. These inspections will include the following:

A visual assessment of the condition of the tank interior in accordance with the American Petroleum Institute (API) Standard 653 for FOST inspections;

Measurements of the thickness of the tank interior coating at several locations in the tank, in accordance with the American Society of Testing Materials Standard ASTM D-1186, for coating thickness measurements; and
Observations for voids and pinholes in the tank coating, in accordance with guidance provided in the National Association of Corrosion Engineers' recommended practice NACE RP0188, "Discontinuity (Holiday) Testing of Protective Coating."

By monitoring the tank in these areas, the inspection program will reduce the possibilities of age-related degradation of the internals in the tank.

Detection of Aging Effects

The AERM are detectable by visual and other non-destruction techniques. Since corrosion of the carbon steel interior surface of the tank cannot occur without degradation of the coating, observing and confirming that the coating is intact constitutes an effective method to ensure that the AERMs have not occurred. The tank coating does not contribute to the tank's intended function. Therefore, observing the coating for degradation provides an alert condition which triggers corrective action before degradation that affects the tank's ability to perform its intended function can occur.

Monitoring and Trending

Under the Tank Inspection Program, XXNPP will perform an internal inspection of the FOSTs at periodic intervals based on results of previous inspections.

The site corrective action program will, if needed, provide trending.

Acceptance Criteria

Plant procedures provide criteria for determining the acceptability of as-found conditions and for initiating the appropriate corrective action. The acceptance criteria and guidance are geared toward avoiding unacceptable degradation of a component, which would cause a loss of intended function.

Confirmation Process

Unacceptable inspection and observation results are evaluated and addressed in the site corrective action process, which calls for follow-up and confirmation steps.

Corrective Action

If degradation is found, corrective actions will be implemented. Future inspections may be scheduled, if appropriate, based on the level and degree of degradation and the specific corrective actions that were implemented.

Administrative Controls

The procedures governing inspections and observations for the Tank Internal Inspection Program are included in the population of procedures subject to 10 CFR 50.59 for control of changes.

Operating Experience

The DFO System has performed well, exhibiting no age-related degradation that impaired the system functions over its history to date.

On November 1, 1995, No. 11 FOST was inspected. The inspection revealed that the tank is in good condition with negligible coating deterioration after approximately 20 years of service. The inspection included a series of ultrasonic tests to measure the thickness of the bottom plates. Since the coating on the tank internal surfaces was found to be intact, no contact between the system fluid and the internal surfaces of the tank is occurring. The inspection concluded that: no deficiencies were observed during tank visual (interior and exterior) inspections; no flaking, blistering, or damaged sections of coating was observed; no deficiencies were observed during vacuum box inspection of welds; and the minimum floor thickness measurement was 0.251 inches, consistent with the original nominal thickness specification for the 1/4 inch plate. No corrosion of tank surfaces was found. Therefore, it can be concluded that no age-related degradation of the carbon steel material of construction has occurred.

On April 13, 1997 No. 21 FOST was inspected and found to be in a similarly good condition.

Demonstration

Carbon steel diesel FOST internal surfaces and internals are susceptible to various aging effects. These aging effects may be compounded by the presence of sludge/deposits at the bottom of the tank where water, if present, will generally collect. Although, the interior surfaces of the FOSTs are covered with a protective coating of a self-curing, inorganic zinc primer (trade name Carbo Zinc 11), no credit is taken for this coating when determining AERM.

If the diesel fuel oil is contaminated with water and comes into contact with the metal surfaces of the tank, loss of material could occur.

Based on the above, the continued implementation of the existing inspections and observations for loss of material and for conditions that can cause it provide reasonable assurance that loss of material of tank internal surfaces will be managed such that certain systems and components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

FSAR Revision

Tank Inspection Program

The Diesel FOST Internal Inspection Program will manage the aging effect, loss of material. The inspections will monitor for flaking, blistering, or damaged sections of coating and inspect the interior tank welds. These inspections include (1) a visual assessment of the condition of the tank interior (2) measurements of the thickness of the tank interior coating (3) observations for voids and pinholes in the tank coating. The inspections and observations are conducted in accordance with the guidelines in API Standard 653, ASTM D-1186 and NACE RP0188.

Chapter 2: Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review, and Implementation Results

2.3 SCOPING AND SCREENING RESULTS: MECHANICAL SYSTEMS

The determination of mechanical systems within the scope of license renewal is made by initially identifying Plant X mechanical systems and then reviewing them to determine which ones satisfy one or more of the criteria contained in 10 CFR 54.4. This process is described in Section 2.1 and the results of the mechanical systems review are contained in Section 2.2. Section 2.1 also provides the methodology for determining the components within the scope of 10 CFR 54.4 that meet the requirements contained in 10 CFR 54.21(a)(1). The components that meet these screening requirements are identified in this section. These identified components subsequently require an aging management review for license renewal.

The screening results are provided below in four subsections:

- Reactor Coolant Systems
- Engineered Safety Features Systems
- Auxiliary Systems
- Steam and Power Conversion Systems.

2.3.4 STEAM AND POWER CONVERSION SYSTEMS

The Steam and Power Conversion Systems act as a heat sink to remove heat from the reactor and convert the heat generated in the reactor to the plant's electrical output. The following systems are included in this subsection:

- Main Steam
- Feedwater and Blowdown
- Auxiliary Feedwater

2.3.4.1 FEEDWATER

The Feedwater System consists of a supply line to each steam generator. A feedwater isolation valve in each steam generator supply line is located just outside the containment penetration. These valves are motor operated, closing automatically on a Steam Generator Isolation Signal (SGIS). A check valve in each supply line, located inside containment, prevents uncontrolled blowdown from the affected steam generator in the event of a feedwater line break.

The license renewal boundary also includes the piping from the steam generators to the isolation valves for the Blowdown and Primary Sampling Systems.

The Feedwater System boundary is denoted by License Renewal (LR) flags on the following drawing:

- 11405-M-253 Sheet 1, Flow Diagram Steam Generator Feedwater and Blowdown P & ID

The list of Feedwater System component types subject to aging management review and their intended functions is shown in Table 2.3.4.1.

Table 2.3.4.1
Feedwater System Component Types Subject to Aging Management Review and their Intended Functions

Component Type	Intended Functions
PIPES and FITTINGS	Pressure Boundary
VALVES	Pressure Boundary
BOLTING	Pressure Boundary

2.3.4.2 AUXILIARY FEEDWATER

The Auxiliary Feedwater (AFW) System supplies feedwater to the steam generators whenever the reactor coolant system temperature is above 300 deg F and the main feedwater system is not in operation. The AFW System contains one safety-related emergency feedwater storage tank, two safety-related pumps, one non-safety-related pump, plus related piping, valves, and instrumentation. One safety-related pump is electric motor driven, and the other is steam turbine driven. The non-safety-related pump is diesel engine driven. The AFW System can supply the steam generators through two different flow paths. One flow path is through an interconnection with the main feedwater piping upstream of the feedwater regulating valves, after which the water enters the each steam generator through the normal feed ring. This flow path is typically used during normal plant heatup and cooldown evolutions. The other flow path connects to the

AFW nozzles on the steam generators. Either safety-related AFW pump can pump water from the EFWST to the steam generators. The non-safety-related AFW pump may be used to pump water from the condensate storage tank to the steam generators. In the event of automatic initiation, such as when the steam generator low level setpoint is reached, the AFW System is designed to automatically start both safety-related AFW pumps and to direct flow to the steam generators via the flow path to the AFW nozzles.

The AFW System boundary is highlighted on the following drawings:

- 11405-M-253 sh. 1, Flow Diagram Steam Generator Feedwater & Blowdown P&ID
- 11405-M-253 sh. 4, Flow Diagram Steam Generator Feedwater & Blowdown P&ID
- 11405-M-254 sh. 2, Flow Diagram Condensate P&ID
- E-4144, FW-10 Lube Oil Schematic P & ID
- EM-1109/1110, Instrument & Control Equipment List
- EM-1368/1369, Instrument & Control Equipment List
- EM-1038, Instrument & Control Equipment List
- EM-1039, Instrument & Control Equipment List
- EM-1117, Instrument & Control Equipment List

The list of Auxiliary Feedwater System component types subject to aging management review and their intended functions is shown in Table 2.3.4.2.

Table 2.3.4.2
Auxiliary Feedwater System Component Types Subject to Aging Management Review and their Intended Functions

Component Type	Intended Functions
ACCUMULATOR	Pressure Boundary
CONTROLLER	Pressure Boundary
FILTER / STRAINER	Pressure Boundary Only
FILTER / STRAINER	Pressure Boundary & Filtration
FLOW ELEMENT / ORIFICE	Pressure Boundary & Flow Measurement
HEAT EXCHANGER	Pressure Boundary
INDICATOR/ RECORDER	Pressure Boundary
PIPE & FITTINGS	Pressure Boundary
PUMP	Pressure Boundary
TRANSMITTER/ ELEMENT	Pressure Boundary
TURBINE	Pressure Boundary
VALVE	Pressure Boundary
TANK	Pressure Boundary
BOLTING	Pressure Boundary
CONTROLLER	Pressure Boundary

Table 2.3.4.2 Auxiliary Feedwater System Component Types Subject to Aging Management Review and their Intended Functions	
Component Type	**Intended Functions**
FLOW ELEMENT / ORIFICE	Pressure Boundary Only
INDICATOR / RECORDER	Pressure Boundary

2.3.4.3 MAIN STEAM AND TURBINE STEAM EXTRACTION

The Main Steam and Turbine Steam Extraction System consists of piping from each steam generator that penetrates the Containment (steam generators are addressed in Sections 2.3.1.3 and 3.2.3). Main steam isolation valves are located in each pipe just outside containment. These pipes connect to a common header which leads to the four turbine stop valves and the Main Steam Isolation Valve (MSIV) in each pipe. Also included in the Main Steam and Turbine Steam Extraction System boundary is the piping to the turbine-driven auxiliary feedwater pump and the associated drains and vents. The MSIV packing leakoff line isolation valve is the boundary prior to the low pressure heaters.

The Main Steam and Turbine Steam Extraction System boundary is highlighted on the following drawing:

- 11405-M-252 Sheet 1, Flow Diagram Steam P & ID

The list of Main Steam and Turbine Steam Extraction System component types subject to aging management review and their intended functions is shown in Table 2.3.4.3.

Table 2.3.4.3 Main Steam and Turbine Steam Extraction System Component Types Subject to Aging Management Review and their Intended Functions	
Component Type	**Intended Functions**
FILTERS/STRAINERS	Pressure Boundary & Filtration
PIPES & FITTINGS	Pressure Boundary
VALVES	Pressure Boundary
BOLTING	Pressure Boundary

2.4 SCOPING AND SCREENING RESULTS: STRUCTURES

The determination of structures within the scope of license renewal is made by initially identifying Plant X structures and then reviewing them to determine which ones satisfy one or more of the criteria contained in 10 CFR 54.4. This process is described in Section 2.1 and the results of the structures review are contained in Section 2.2. Section 2.1 also provides the methodology for determining the components within the scope of 10 CFR 54.4 that meet the requirements contained in 10 CFR 54.21(a)(1). The structures that meet these screening requirements are identified in this section. These identified structures subsequently require an aging management review for license renewal.

2.4.1 CONTAINMENT

The Containment structure is a domed cylinder 140'-4 3/4" high with an outside radius of 58'-10 3/4". The structure is a partially prestressed, reinforced concrete Class I structure composed of cylindrical walls, domed roof and a bottom mat. The mat is common to both the Containment structure and the Auxiliary Building and is supported on steel piles driven to bedrock. The mat incorporates a depressed center portion for the reactor vessel. The Containment has a 1/4" internal carbon steel liner which maintains an essentially leak-tight boundary. The unbonded tendons are in conduits filled with waterproof grease. The tendon anchors are accessible for inspection, testing, and re-tensioning via the tendon access gallery located directly beneath the cylinder walls and at the dome roof.

The reinforced concrete internal structure consists of several levels/compartments supported on the mat by concrete columns. The internal structure is isolated from the Containment shell by a shake space which also permits the distribution and dissipation of any internal differential pressure during postulated accident events. The various floors are at elevations 1060'-0" (concrete), 1056'-8" (steel), 1045'-0" (concrete), and 1013'-0" (concrete). There are several compartments which house mechanical equipment. They are the steam generator and reactor coolant pump compartments, pressurizer compartment, and the reactor cavity.

The Containment structure houses a substantial amount of safety-related and non-safety related mechanical and electrical equipment. There are many mechanical piping and electrical penetrations through the cylinder walls.

The system boundary includes all concrete, steel, elastomer, and fire barrier components within the domed roof (approximate elevation 1031'-5") and cylinder walls (approximate radius of 58'-10"). This includes any components attached to the outside of the cylinder or dome above the Auxiliary Building roof. The post-tensioned tendons, the tendon gallery, equipment and personnel hatches are within the system boundary. The mechanical and electrical penetration sleeves, bellows, and any welds between the sleeve and the liner are included in the system boundary. For each mechanical penetration, the weld between the penetration and the pipe is not within the boundary (see various application sections for the pertinent safety-related and non-safety related systems). The list of Containment component types subject to aging management review and their intended functions is shown in Table 2.4.1.

Table 2.4.1 Containment Component Types Subject to Aging Management Review and Their Intended Functions	
Component Type	**Intended Functions**
Concrete above Ground	Flood protection barrier
Concrete above Ground	Radiation shielding
Concrete above Ground	Shelter, protect and support safety-related components
Concrete above Ground	Spray shield or curbs
Concrete above Ground	Pressure boundary
Concrete above Ground	Missile barrier
Concrete above Ground	Pipe whip restraint
Concrete above Ground	Shielding against high energy line breaks
Concrete below Ground	Flood protection barrier
Concrete below Ground	Radiation shielding
Concrete below Ground	Shelter, protect and support safety-related components
Concrete below Ground	Spray shield or curbs
Concrete below Ground	Pressure boundary
Concrete below Ground	Missile barrier
Concrete below Ground	Pipe whip restraint
Concrete below Ground	Shielding against high energy line breaks
Concrete Interior	Flood protection barrier
Concrete Interior	Radiation shielding
Concrete Interior	Shelter, protect and support safety-related components
Concrete Interior	Spray shield or curbs
Concrete Interior	Pressure boundary
Concrete Interior	Missile barrier
Concrete Interior	Pipe whip restraint
Concrete Interior	Shielding against high energy line breaks
Grout Protected from Weather	Support safety-related components
Structural Steel in Air	Pipe whip restraint
Structural Steel in Air	Support safety-related components
Carbon Steel Threaded Fasteners	Support non-safety-related components
Carbon Steel Threaded Fasteners	Pressure boundary
Carbon Steel Threaded Fasteners	Shelter, protect and support safety-related

Table 2.4.1
Containment Component Types Subject to Aging Management Review and Their Intended Functions

	components
Carbon Steel Threaded Fasteners	Missile barrier
Stainless Steel Threaded Fasteners	Pressure boundary
Equipment Hatch Gasket	Pressure boundary
Steel Liner	Pressure boundary
Refueling Pool Liner	Pressure boundary
Reactor Cavity Seal Ring	Pressure boundary
Post-Tensioned Tendons	Pressure boundary
Electrical Penetrations	Pressure boundary
Mechanical Penetrations	Pressure boundary
Post-Tensioned Tendons	Shelter, protect and support safety-related components
Post-Tensioned Tendons	Missile barrier
Containment Penetrations With Bellows	Pressure boundary
Trisodium Phosphate Baskets	Shelter, protect and support safety-related components
Equipment Hatch	Pressure boundary
Personnel Air Lock	Pressure boundary
Fuel Transfer Tube	Pressure boundary
Reactor Vessel Missile Shields	Missile barrier

2.4.2 *Other Structures*

The following structures are included in this subsection

- Auxiliary Building
- Intake Structure
- Turbine Building

2.4.2.1. Auxiliary Building

2.4.2.2. Intake Structure

The Intake Structure is a multi-floored Class 1 structure with an operating floor at elevation 1007'-6". From elevation 960'-10" (bottom of the foundation mat) to elevation 1014'-6", the structure is a box-type reinforced concrete structure with internal bracing provided by concrete walls and floor slabs. The mat foundation is supported on steel pipe piles driven to bedrock. From elevation 1014'-6" to elevation 1035'-7 1/2" (roof elevation), the structure is a braced steel frame clad with aggregate resin panels. The multi-layered built-up roof is supported by metal decking spanning between open web steel joists. The Intake Structure houses and protects both CQE and non-CQE systems and components. The diesel driven fire pump fuel tank enclosure is included in the Intake Structure.

The system boundary includes all concrete, steel, elastomer, and fire barrier components from elevation 960'-10" to elevation 1037'-6" between column lines 101 and 106 and from a distance 11'-8" East of column line AA to a distance 21'-10 3/8" West of column line DD. The enclosure for the Diesel Driven Fire Pump Fuel Tank is included in the system boundary. The circulating water intake and discharge tunnels are not within the system boundary. Component Supports (e.g. pipe supports, cable tray supports, equipment supports, and equipment anchorage) and Piles are to be evaluated as commodities.

A complete list of Intake Structure component types subject to aging management review and their intended functions is shown in Table 2.4.2.2.

Table 2.4.2.2
Intake Structure Component Types Subject to Aging Management Review and Their Intended Functions

Component Type	Intended Functions
Carbon Steel Threaded Fasteners	Flood protection barrier
Carbon Steel Threaded Fasteners	support non-safety-related components
Concrete above Ground	Flood protection barrier
Concrete above Ground	Flood protection barrier
Concrete above Ground	Shelter, protect and support safety-related components
Concrete above Ground	Source of cooling water
Concrete in a Fluid Environment	Flood protection barrier
Concrete in a Fluid Environment	Source of cooling water
Concrete in a Fluid Environment	Support safety-related components
Concrete Interior	Flood protection barrier
Concrete Interior	Missile barrier
Concrete Interior	Shelter, protect and support safety-related components
Flood Panel Seals	Flood protection barrier
Grout Protected From Weather	Support safety-related components
Structural Steel	Flood protection barrier
Structural Steel	Shelter and protect safety-related components

2.4.2.3. Turbine Building

The Turbine Building is a multi-floored Class II structure with an operating floor at elevation 1036'. From the basement floor elevation of 990' to elevation 1007'-6", the structure is a box-type, reinforced concrete structure with internal bracing provided by concrete walls, floor slabs and structural steel. The mat foundation is supported on steel piles driven to bedrock. From elevation 1007'-6" to the roof elevation of 1095'-5", the structure is braced steel frame clad with aggregate resin panels. The multi-layered built-up roof is supported by metal decking spanning between open web steel joists. The turbine generator is located on the operating floor. It is supported by a mass concrete structure referred to as the turbine pedestal. The turbine pedestal is independent from the Turbine Building structure. The Turbine Building houses both Limited CQE and non-CQE systems and components.

Main steam and feed water High Energy Line Break (HELB) restraints and shields are located in the Turbine Building.

The system boundary includes all concrete and steel East of the Auxiliary Building, between column lines 1 and 9 and from 3'-0" East of column line A to 3'-0" West of column line B. The circulating water intake and discharge tunnels are not within the Turbine Building system boundary. Component Supports (e.g. pipe supports, cable tray supports, conduit supports, equipment supports and equipment anchorage) and Piles are evaluated as commodities.

A complete list of Turbine Building component types subject to aging management review and their intended functions is shown in Table 2.4.2.3.

Table 2.4.2.3
Turbine Building Component Types Subject to Aging Management Review and Their Intended Functions

Component Type	Intended Functions
Carbon Steel Threaded Fasteners	Support non-safety-related components
Concrete above Ground	Support non-safety-related components
Concrete below Ground	Support non-safety-related components
Concrete Interior	Support non-safety-related components
Grout Protected From Weather	Shield against high energy line break
Grout Protected From Weather	Pipe whip support
Grout Protected From Weather	Support non-safety-related components
Structural Steel	Support non-safety-related components

Chapter 3 AGING MANAGEMENT REVIEW RESULTS

For those structures and components that are identified as being subject to an aging management review, 10 CFR 54.21(a)(3) requires demonstration that the effects of aging will be adequately managed so that their intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation. The information provided in this chapter provides essential input to the required aging management review as it identifies and discusses the aging effects requiring management.

This chapter describes the results of the aging management reviews of the components and structures, identified in Chapter 2, Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review, and Implementation Results. This chapter:

- provides references to the descriptions of common aging management programs
- identifies the components and structural components subject to aging management review, and their intended functions
- discusses the materials and internal and external environments
- describes or references the processes used to identify aging effects
- describes industry and plant-specific operating experiences with respect to the aging effects
- identifies the aging effects requiring management
- lists the aging management programs for aging effects requiring management.

For those structures and components identified as being subject to an aging management review, the results are contained in Section 3.1 for Reactor Coolant Systems, Section 3.2 for Engineered Safety Features Systems, Section 3.3 for Auxiliary Systems, Section 3.4 for Steam And Power Conversion Systems, Section 3.5 for Structures and Structural Components, and Section 3.6 for Electrical and Instrumentation and Controls. Aging management program descriptions are contained in Appendix B.

3.4 Aging Management of Steam and Power Conversion System

The Plant X systems evaluated in this section of the application consist of the main steam and extraction steam systems, the main and auxiliary feedwater systems, condensate system, steam generator blowdown system and associated components.

The Main Steam System consists of piping from each steam generator that penetrates the containment wall to the main steam isolation valves that are located in each pipe just outside containment. The Extraction Steam System consists of steam lines leading from the turbine to the feedwater heaters including drains. Also included in the Main Steam and Extraction Steam System boundary is the piping to the turbine-driven auxiliary feedwater pump and the associated drains and vents.

The Feedwater System consists of a supply line to each steam generator. A feedwater isolation valve in each steam generator supply line is located just outside the containment penetration. These valves are motor operated, closing automatically on a Steam Generator Isolation Signal (SGIS). A check valve in each supply line, located inside containment, prevents uncontrolled blowdown from the affected steam generator in the event of a feedwater line break. The Feedwater System boundary also includes the piping from the steam generators to the isolation valves for the Blowdown and Primary Sampling Systems.

The Auxiliary Feedwater (AFW) System supplies feedwater to the steam generators whenever the reactor coolant system temperature is above 300 degrees F and the main feedwater system is not in operation. The AFW System contains one safety-related emergency feedwater storage tank (EFWST), two safety-related pumps, one non-safety-related pump, plus related piping, valves, and instrumentation. One safety-related pump is electric motor driven, and the other is steam turbine driven. The non-safety-related pump is diesel engine driven. The AFW System can supply the steam generators through two different flow paths. One flow path is through an interconnection with the main feedwater piping upstream of the feedwater regulating valves, after which the water enters the each steam generator through the normal feed ring. This flow path is typically used during normal plant heatup and cooldown evolutions. The other flow path connects to the AFW nozzles on the steam generators. Either safety-related AFW pump can pump water from the EFWST to the steam generators. The non-safety-related AFW pump may be used to pump water from the condensate storage tank to the steam generators. In the event of automatic initiation, such as when the steam generator low level setpoint is reached, the AFW System is designed to automatically start both safety-related AFW pumps and to direct flow to the steam generators via the flow path to the AFW nozzles.

OPERATING EXPERIENCE:

Site: Searches were conducted of pertinent site records, including the Condition Report (CR) system, and discussions were held with appropriate site personnel. These efforts revealed no evidence of additional aging effects requiring management.

Industry: Searches were conducted of industry records. These reviews revealed no evidence of additional aging effects requiring management.

3.4.1 Aging Management Programs Evaluated in the GALL Report that Are Relied on for License Renewal

Table 3.4.1 shows the component groups (combinations of materials and environments), and aging management programs evaluated in the GALL Report that are relied on for license renewal of the Steam and Power Conversion System for Plant X.

3.4.1.1 Further Evaluation of Aging Management as Recommended by GALL

3.4.1.1.1 Thermal Fatigue

Fatigue was not identified as a TLAA for Plant X. Thermal fatigue was identified as an aging effect requiring management. The Fatigue Monitoring Program described in Appendix B manages fatigued.

3.4.1.1.2 Water Chemistry

GALL Report Sections VIII G1.1 and VIII G1.2 indicate that the verification of the effectiveness of the water chemistry program should be conducted with an inspection of stagnant flow locations within the systems. These inspections are either being conducted in accordance with the Periodic Surveillance and Preventive Maintenance Program or will be conducted in accordance with the Age-Related Degradation Inspection Program prior to expiration of the current license. Both programs are described in Appendix B.

3.4.1.1.3 Carbon steel components of oil coolers in oil

The loss of material due to microbiologically influenced corrosion is only applicable to carbon steel components of oil coolers at Plant X because the environment for auxiliary feedwater piping is only treated water. If there is a potential for water contamination and water pooling in a lube oil system, loss of material due to general corrosion and microbiologically influenced corrosion are concerns for carbon steel. Corrosion is therefore considered to be an aging effect requiring management due to the need to

Table 3.4.1

Aging Management Programs Evaluated in the GALL Report that Are Relied on for License Renewal

Component Group	***Aging Effect / Mechanism***	***Aging Management Program***	***GALL Further evaluation recommended***	***Discussion***
Piping and fittings in main feedwater line and in steam line	Cumulative fatigue damage	Fatigue Monitoring Program	Yes, TLAA.	See Section 3.4.1.1.1
Carbon steel piping, valve bodies, pump casing, and tanks. (except main steam system)	Loss of material	Water Chemistry	Yes, detection of aging effects should be further evaluated	This group includes low alloy steel components at Plant X. See Section 3.4.1.1.2 for discussion of further evaluation.
Oil coolers	Loss of material from general and microbiologically influenced corrosion	Periodic Surveillance and Preventive Maintenance	Yes, plant specific	See Section 3.4.1.1.3
Carbon steel piping, valve bodies, and pump casings	Wall thinning from flow-accelerated corrosion	Flow Accelerated Corrosion	No	The information in the GALL report bounds Plant X
Carbon steel piping and valve bodies in main steam system	Loss of material from crevice and pitting corrosion	Water Chemistry	No	This group includes low alloy steel components at Plant

Table 3.4.1

Aging Management Programs Evaluated in the GALL Report that Are Relied on for License Renewal

Component Group	*Aging Effect / Mechanism*	*Aging Management Program*	*GALL Further evaluation recommended*	*Discussion*
				X. The information in the GALL report bounds Plant X
External surface of carbon steel components	Loss of material from atmospheric corrosion	General Corrosion of External Surfaces		Aging management program is different from that described in GALL – see Section 3.4.1.2.1
Closure bolting in high-pressure or high-temperature systems	Loss of material from atmospheric corrosion and crack initiation and growth from cyclic loading, stress corrosion cracking.	General Corrosion of External Surfaces		Aging management program is different from that described in GALL – see Section 3.4.1.2.2

employ periodic lube oil sampling to ensure that water is not present, thereby confirming that the condition which could potentially cause this aging effect does not exist.

As discussed in Appendix B the Periodic Surveillance and Preventive Maintenance ensures water is not present in lubricating oil and that the oil is changed on a refueling frequency.

3.4.1.2 Aging Management Programs or Evaluations that Are Different from those Described in the GALL Report

3.4.1.2.1 External surfaces of carbon steel components

Carbon steel items (with or without an external coating) in a plant indoor air external environment are susceptible to external general corrosion, although such corrosion would be minimal if the carbon steel remains in a dry condition. As discussed in Appendix B the General Corrosion of External Surfaces Program manages this aging effect.

3.4.1.2.2 Pressure boundary bolting on treated water or oil systems

Crack initiation and growth from cyclic loading, stress corrosion cracking has not been observed in closure bolting on systems containing non-borated treated water and on systems containing oil located in a plant indoor air external environment.

General corrosion is an aging effect requiring management for closure bolting due to the potential for external leakage of the process fluid, although external leakage of non-borated treated water would not be expected to rapidly corrode bolting.

No aging effects requiring management were identified for pressure boundary bolting on oil systems because (1) the bolting is routinely exposed to a plant indoor air environment which is not conducive to any aging effects, and (2) external leakage of oil will not corrode carbon or low-alloy steel bolting materials.

As discussed in Appendix B the General Corrosion of External Surfaces Program manages this aging effect.

3.4.2 Components or Aging Effects that Are Not Addressed in the GALL Report

Table 3.4.2 contains Steam and Power Conversion System aging management review results for internal and external environments. These tables include the component types, materials, environments, aging effects requiring management, and the programs and activities for managing aging.

The following combinations of materials and environments exist for the components subject to aging management in the Steam and Power Conversion System.

- Aluminum in Oil
- Copper Alloy in Oil
- Copper Alloy in Treated Water
- Glass in Oil or Treated Water
- Stainless Steel in Treated Water and Saturated steam
- Stainless Steel in Oil
- Aluminum in Plant Indoor Air
- Copper Alloy in Plant Indoor Air
- Stainless Steel in Plant Indoor Air
- Glass in Plant Indoor Air

3.4.2.1 Aluminum in Oil

Component Group Description:

This group includes aluminum and aluminum alloy items with a lubricating oil internal environment.

Aging Effects Requiring Management, and Mechanisms:

Loss of Material

If there is a potential for water contamination and water pooling in a lube oil system, loss of material is a concern. Loss of material is therefore an aging effect requiring management due to the need to employ periodic lube oil sampling to ensure that water is not present.

Aging Management Program

As discussed in Appendix B the Periodic Surveillance and Preventive Maintenance ensures water is not present in lubricating oil and that the oil is changed on a refueling frequency.

3.4.2.2 Copper Alloy in Oil

Component Group Description:

This group includes copper and copper alloy items in a lubricating oil internal environment.

Aging Effects Requiring Management, and Mechanisms:

Loss of Material

There is a potential for loss of material of copper alloys in a treated water environment if the zinc content of the material is greater than 15%. Loss of material is identified as an aging effect requiring management for items in this group because their specific zinc content could not be confirmed to be in a range where loss of material aging effects are not plausible.

Aging Management Program

As discussed in Appendix B the Periodic Surveillance and Preventive Maintenance ensures water is not present in lubricating oil and that the oil is changed on a refueling frequency.

3.4.2.3 Copper Alloy in Treated Water

Component Group Description:

Includes copper & copper alloy items in treated water as an internal environment.

Aging Effects Requiring Management, and Mechanisms:

Loss of Material

If there is a potential for water contamination and water pooling in a lube oil system, loss of material is a concern. Loss of material is therefore an aging effect requiring management due to the need to employ periodic lube oil sampling to ensure that water is not present

Aging Management Program

As discussed in Appendix B the Periodic Surveillance and Preventive Maintenance ensures water is not present in lubricating oil and that the oil is changed on a refueling frequency.

3.4.2.4 Glass in Oil or Treated Water

Component Group Description:

This AMR group covers glass items, such as sight glasses, where the glass functions as part of a fluid pressure boundary, and the internal environment is oil or water.

Aging Effects Requiring Management, and Mechanisms:

Sight glasses are used in applications such as local tank level indicators and pipe flow indicators. The glass functions as part of the pressure.boundary of the respective system.

Glass is an amorphous inorganic oxide cooled to a rigid condition without crystallization. Depending on the desired properties of the glass, varying amounts of modifiers, fluxes, and stabilizers are added. Glass is susceptible to hydrofluoric and caustic attack and it is subject to slight attack by hot water. It is hydrolytically decomposed during hot water attack rather than dissolved. Its resistance to hot water is dependent on the composition of the glass (e.g., modifiers, fluxes, and stabilizers). Uniform or selective attack can occur.

The glass of level gauges and flow indicators is exposed to chemically controlled DI water in various plant tanks and pipelines at essentially ambient temperature. It is not exposed to hot water, hydrofluoric, or caustic conditions.

The glass is not exposed to conditions that may degrade it. Glass is unaffected by aging mechanisms and is not subject to any aging effects requiring management.

3.4.2.5 Stainless Steel in Treated Water and Saturated Steam

Component Group Description:

This group includes stainless steel components with an internal environment of treated water.

Aging Effects Requiring Management, and Mechanisms:

Loss of Material - Pitting Corrosion

Pitting corrosion is not a plausible aging effect for stainless steel in a treated water environment if halogens are less than 150 ppb and sulfates are less than 100 ppb. Pitting corrosion is considered to be an aging effect requiring management due to the need to adhere to chemistry limits for treated water which ensure that these parameters are in a range where this mechanism is not plausible.

Loss of Material - Crevice Corrosion

Crevice corrosion is not a plausible aging effect for stainless steel in a treated water environment if the dissolved oxygen level is less than 100 ppb. Crevice corrosion is considered to be an aging effect requiring management due to the need to adhere to chemistry limits for treated water which ensure that these parameters are in a range where this mechanism is not plausible.

Cracking

Cracking is not a plausible aging effect for stainless steel in a treated water environment if halogens are less than 150 ppb and sulfates are less than 100 ppb. Cracking is considered to be an aging effect requiring management due to the need to adhere to chemistry limits for treated water which ensure that these parameters are in a range where this mechanism is not plausible.

Aging Management Program

As discussed in Appendix B the Water Chemistry and Closed-Cycle Cooling Water Program ensures water chemistry limits are maintained.

3.4.2.6 Stainless Steel in Oil

Component Group Description:

This group includes stainless steel items with lubricating oil as an internal environment.

Aging Effects Requiring Management, and Mechanisms:

Loss of Material

If there is a potential for water contamination and water pooling in a lube oil system, loss of material due to pitting & crevice corrosion is a concern. Loss of material due to galvanic corrosion can also be a concern if the stainless steel is in contact with a more cathodic material such as brass/bronze; however, galvanic corrosion is not an issue if there is no water present to provide an electrolytic environment. Loss of material is therefore conservatively identified as an aging effect requiring management due to the need to employ periodic lube oil sampling to ensure that water is not present, thereby confirming that the condition which could potentially cause this aging effect does not exist.

Aging Management Program

As discussed in Appendix B the Periodic Surveillance and Preventive Maintenance ensures water is not present in lubricating oil and that the oil is changed on a refueling frequency.

3.4.2.7 Aluminum in Plant Indoor Air

Component Group Description:

This group includes aluminum and aluminum alloy items with an external environment of plant indoor air.

Aging Effects Requiring Management, and Mechanisms:

None

No aging effects were identified for aluminum in an air environment. Aluminum in an indoor air environment is not susceptible to galvanic corrosion due to absence of significant electrolyte in plant indoor air. Items in this group are not susceptible to a wetted environment.

3.4.2.8 Copper Alloy in Plant Indoor Air

Component Group Description:

This group includes copper and copper alloy items (e.g., brass, bronze) with an external environment of plant indoor air.

Aging Effects Requiring Management, and Mechanisms:

None

No aging effects for copper alloy in an indoor air environment were identified. Galvanic corrosion is not a concern because plant indoor air is not a significant electrolytic environment. Copper alloy is not susceptible to a wetted (water) external environment.

3.4.2.9 Stainless Steel in Plant Indoor Air

Component Group Description:

This group includes all 300 series, stainless steel items exposed only to plant indoor air (i.e., valve bodies, bolts,etc.).

Aging Effects Requiring Management, and Mechanisms:

None

No aging effects were identified for stainless steel in plant indoor air. Other chemicals must also be present (i.e., halide ions, bromides, chlorides, etc.) which are not present in sufficient quantity to justify aging effects for this material/environment.

3.4.2.10 Glass in Plant Indoor Air

Component Group Description:

This group includes glass items (e.g., sight glasses, level glasses) with an external environment of plant indoor air.

Aging Effects Requiring Management, and Mechanisms:

None

The glass is not exposed to conditions that may degrade it. Glass is unaffected by aging mechanisms and is not subject to any aging effects requiring management.

3.4.3 Conclusion

The aging effects requiring management are adequately managed by the following programs:

Water Chemistry and Closed-Cycle Cooling Water Program
General Corrosion of External Surfaces Program
Age Related Degradation Inspection Program
Periodic Surveillance and Preventive Maintenance Program

These programs are described in Appendix B.

Table 3.4.2
Steam and Power Conversion System Component Types Subject to Aging Management

Component Types	Material	Environment	AERMs	Program/Activity
Pipes, Fittings and Valves	Stainless Steel	Treated Water (greater than 200 deg F)	Loss of Material	Water Chemistry and Closed-Cycle Cooling Water Program
Bolting	Stainless Steel	Containment Air/Plant Indoor Air	None	None Required
Pipes, Fittings, Valves Filter/Strainer, Heat Exchanger, Flow Element/Orifice, Transmitter Element	Stainless Steel	Containment Air/Plant Indoor Air	None	None Required
Pipes, Fittings and Valves	Stainless Steel	Saturated Steam	Cracking	Water Chemistry and Closed-Cycle Cooling Water Program
Pipes, Fittings and Valves	Stainless Steel	Saturated Steam	Loss of Material	Water Chemistry and Closed-Cycle Cooling Water Program
Pump	Aluminum	Lubricating Oil possibly contaminated with water	Loss of Material	Periodic Surveillance and PM Program
Pump	Aluminum	Plant Indoor Air	None	None Required
Heat Exchanger	Copper Alloy	<90°C(194°F) Treated Water	Loss of Material - Selective Leaching	Age-Related Degradation Inspection (ARDI)
Heat Exchanger	Copper Alloy	<90°C(194°F) Treated Water	Loss of Material - Wear	Age-Related Degradation Inspection (ARDI)
Pipes, Fittings, Valves Filter/Strainer, Heat Exchanger	Copper Alloy	Lubricating Oil possibly contaminated with water	Loss of Material	Periodic Surveillance and PM Program
Pipes, Fittings, Valves Filter/Strainer, Heat Exchanger	Copper Alloy	Plant Indoor Air	None	None Required

Table 3.4.2
Steam and Power Conversion System Component Types Subject to Aging Management

Component Types	Material	Environment	AERMs	Program/Activity
Indicator/Recorder	Glass	<90°C(194°F) Treated Water	None	None Required
Indicator/Recorder	Glass	Lubricating Oil possibly contaminated with water	None	None Required
Indicator/Recorder	Glass	Plant Indoor Air	None	None Required
Pipes, Fittings, Valves Filter/Strainer, Heat Exchanger, Flow Element/Orifice, Transmitter Element	Stainless Steel	<90°C(194°F) Treated Water	Cracking	Water Chemistry and Closed-Cycle Cooling Water Program Age-Related Degradation Inspection (ARDI)
Pipes, Fittings, Valves Filter/Strainer, Heat Exchanger, Flow Element/Orifice, Transmitter Element	Stainless Steel	<90°C(194°F) Treated Water	Loss of Material	Water Chemistry and Closed-Cycle Cooling Water Program Age-Related Degradation Inspection (ARDI)
Filter/Strainer	Stainless Steel	Lubricating Oil possibly contaminated with water	Cracking	Water Chemistry and Closed-Cycle Cooling Water Program

3.5 Aging Management of Containment, Structures and Component Supports

The structures and components for Plant X evaluated in this section of the application consist of the containment, Class 1 structures and associated component supports.

The Containment structure is a domed cylinder 140'-4 3/4" high with an outside radius of 58'-10 3/4". The structure is a partially prestressed, reinforced concrete Class I structure composed of cylindrical walls, domed roof and a bottom mat. The mat is common to both the Containment structure and the Auxiliary Building and is supported on steel piles driven to bedrock. The mat incorporates a depressed center portion for the reactor vessel. The Containment has a 1/4" internal carbon steel liner that maintains an essentially leak-tight boundary. The unbonded tendons are in conduits filled with waterproof grease. The tendon anchors are accessible for inspection, testing, and re-tensioning via the tendon access gallery located directly beneath the cylinder walls and at the dome roof.

The reinforced concrete internal structure consists of several levels/compartments supported on the mat by concrete columns. The internal structure is isolated from the Containment shell by a shake space that also permits the distribution and dissipation of any internal differential pressure during postulated accident events. The various floors are at elevations 1060'-0" (concrete), 1056'-8" (steel), 1045'-0" (concrete), and 1013'-0" (concrete). There are several compartments that house mechanical equipment. They are the steam generator and reactor coolant pump compartments, pressurizer compartment, and the reactor cavity.

The Class 1 Structures at Plant X consist of the auxiliary building, turbine building, and intake structure. The control room is located within the auxiliary building.

The Turbine Building is a multi-floored Class II structure with an operating floor at elevation 1036'. From the basement floor elevation of 990' to elevation 1007'-6", the structure is a box-type, reinforced concrete structure with internal bracing provided by concrete walls, floor slabs and structural steel. The mat foundation is supported on steel piles driven to bedrock. From elevation 1007'-6" to the roof elevation of 1095'-5", the structure is braced steel frame clad with aggregate resin panels. The multi-layered built-up roof is supported by metal decking spanning between open web steel joists. The turbine generator is located on the operating floor. It is supported by a mass concrete structure referred to as the turbine pedestal. The turbine pedestal is independent from the Turbine Building structure. The Turbine Building houses both Limited CQE and non-CQE systems and components.

The Intake Structure is a multi-floored Class 1 structure with an operating floor at elevation 1007'-6". From elevation 960'-10" (bottom of the foundation mat) to elevation

1014'-6", the structure is a box-type reinforced concrete structure with internal bracing provided by concrete walls and floor slabs. The mat foundation is supported on steel pipe piles driven to bedrock. From elevation 1014'-6" to elevation 1035'-7 1/2" (roof elevation), the structure is a braced steel frame clad with aggregate resin panels. The multi-layered built-up roof is supported by metal decking spanning between open web steel joists. The Intake Structure houses and protects both CQE and non-CQE systems and components. The diesel driven fire pump fuel tank enclosure is included in the Intake Structure.

OPERATING EXPERIENCE:

Site: Searches were conducted of pertinent site records, including the Condition Report (CR) system, and discussions were held with appropriate site personnel. These efforts revealed no evidence of additional aging effects requiring management.

Industry: Searches were conducted of industry records. These reviews revealed no evidence of additional aging effects requiring management.

3.5.1 Aging Management Programs Evaluated in the GALL Report that Are Relied on for License Renewal

Table 3.5.1 shows the component groups (combinations of materials and environments), and aging management programs evaluated in the GALL Report that are relied on for license renewal of the Structures and Component Supports for Plant X.

Table 3.5.1
Aging Management Programs Evaluated in the GALL Report that Are Relied on for License Renewal

Component Group	Aging Effect / Mechanism	Aging Management Program	GALL Further evaluation recommended	Discussion
Containment				
Penetration sleeves, bellows, and dissimilar metal welds	Cracking for cyclic loading & crack initiation and growth from SCC	Containment inservice inspection and containment leak rate test	Yes, detection of aging effects should be further evaluated	See Section 3.5.1.1.1
Penetration sleeves, penetration bellows, and dissimilar metal welds	Loss of material from corrosion	Containment inservice inspection and containment leak rate test	No	The information in the GALL report bounds Plant X.
Personnel airlock and equipment hatch	Loss of material from corrosion	Containment inservice inspection and containment leak rate test	No	The information in the GALL report bounds Plant X.
Personnel airlock and equipment hatch	Mechanical Wear of Locks, Hinges and Closure Mechanisms required to maintain the airlock/hatch in the closed position	Containment inservice inspection	No	The information in the GALL report bounds Plant X

Table 3.5.1
Aging Management Programs Evaluated in the GALL Report that Are Relied on for License Renewal

Component Group	Aging Effect / Mechanism	Aging Management Program	GALL Further evaluation recommended	Discussion
Equipment hatch gasket	Loss of sealant and leakage through containment from deterioration of seals, gaskets, and moisture barriers	Containment inservice inspection and containment leak rate test	No	The information in the GALL report bounds Plant X
Concrete elements: Basemat, exterior walls below grade.	Aging of inaccessible concrete areas due to leaching of calcium hydroxide, aggressive chemical attack, and corrosion of embedded steel	Containment inservice inspection	Yes, for inaccessible areas	Aging evaluation different from that described in GALL – see Section 3.5.1.2.1
Concrete elements: Basemat	Cracks, distortion, and increases in components stress level from settlement	Containment structure settlement monitoring	Yes. if applicable, proper functioning of de-watering system should be evaluated	Aging evaluation different from that described in GALL – see Section 3.5.1.2.2
Concrete elements: Foundation	Reduction in foundation strength from erosion of porous concrete	Containment structure settlement monitoring	Yes. if applicable, proper functioning of de-watering system should be evaluated	Aging evaluation different from that described in GALL – see Section

Table 3.5.1
Aging Management Programs Evaluated in the GALL Report that Are Relied on for License Renewal

Component Group	Aging Effect / Mechanism	Aging Management Program	GALL Further evaluation recommended	Discussion
	subfoundation			3.5.1.2.2
Concrete elements: Basemat, dome, and wall	Loss of strength and modulus from elevated temperature	Plant-specific	Yes, for any portions of concrete containment that exceed specified temperature limits	Aging evaluation different from that described in GALL – see Section 3.5.1.2.3
Steel elements: Liner plates and steel structures	Aging of inaccessible steel areas: Loss of material from corrosion	Containment inservice inspection and containment leak rate test	Yes, for inaccessible areas	See Section 3.5.1.1.2
Prestressed containment: Tendons and anchorage components	Loss of material from corrosion of prestressing tendons, anchorage components	Containment inservice inspection	No	The information in the GALL report bounds Plant X
Concrete elements Basemat, dome, and wall	Scaling, cracking, and spalling from freeze-thaw; expansion and cracking from reaction with aggregates	Containment inservice inspection	No	Aging evaluation different from that described in GALL – see Section 3.5.1.2.4
Liners	Crack initiation and	Monitoring of the leak	No	The information in

Table 3.5.1
Aging Management Programs Evaluated in the GALL Report that Are Relied on for License Renewal

Component Group	Aging Effect / Mechanism	Aging Management Program	GALL Further evaluation recommended	Discussion
	growth from SCC and loss of material from crevice corrosion	in fuel storage facility		the GALL report bounds Plant X
Turbine and Auxiliary Buildings				
Accessible interior and exterior concrete & steel components.	All types of aging effects	Structures monitoring	No – All Class 1 structures are within the scope of the Plant X structures monitoring program.	Aging evaluation different from that described in GALL – see Sections 3.5.1.2.1 through 3.5.1.2.4. The information in the GALL report bounds Plant X for steel components
Liners	Crack initiation and growth from SCC and loss of material from crevice corrosion	Monitoring of the leak in fuel storage facility	No	The information in the GALL report bounds Plant X

Table 3.5.1
Aging Management Programs Evaluated in the GALL Report that Are Relied on for License Renewal

Component Group	Aging Effect / Mechanism	Aging Management Program	GALL Further evaluation recommended	Discussion
Intake Structure				
All accessible/inaccessible concrete & steel components	All types of aging effects including loss of material from abrasion; cavitation & corrosion	Inspection of water-controlled structures	No	Aging evaluation different from that described in GALL – see Sections 3.5.1.2.1 through 3.5.1.2.5. The information in the GALL report bounds Plant X for steel components
Component Supports				
Support members, anchor bolts, and welds, Concrete surrounding anchor bolts, grout pad, Bolted friction connections etc.	Aging of component supports	Structures monitoring	No, all component supports are within the scope of the applicant's structures monitoring program	The information in the GALL report bounds Plant X
Support members,	Loss of material	Boric acid corrosion	No	The information in

Table 3.5.1
Aging Management Programs Evaluated in the GALL Report that Are Relied on for License Renewal

Component Group	Aging Effect / Mechanism	Aging Management Program	GALL Further evaluation recommended	Discussion
anchor bolts, and welds	from boric acid corrosion			the GALL report bounds Plant X
Support members, anchor bolts, welds, Spring hangers, guides, stops, and vibration isolators	Loss of material from environ-mental corrosion; Loss of mechanical function; and Cracking from cyclic loading	Inservice inspection	No	The information in the GALL report bounds Plant X

3.5.1.1 Further Evaluation of Aging Management as Recommended by GALL

3.5.1.1.1 Containment Penetrations with Carbon Steel Bellows

GALL Report Section II.A.3.1 indicates that the in-service inspection program be augmented when stress corrosion cracking is a concern for dissimilar welds. No dissimilar welds were identified for the Containment Penetrations with Carbon Steel Bellows Component Group. Therefore, the information in the GALL report bounds Plant X.

3.5.1.1.2 Containment Steel Liner

The seal between the containment floor and the containment steel liner is inspected as part of the Containment Inservice Inspection Program. If this seal were determined to be damaged then appropriate portion of the liner would be accessed and inspected.

3.5.1.2 Aging Management Programs or Evaluations that Are Different from those Described in the GALL Report

3.5.1.2.1 Concrete Below Grade

Concrete that is below grade is exposed to the chemicals in the groundwater or untreated water. The concrete is Class A (compressive strength of 5000 psi, water-to-cement ratio is 4.25 gallons/sack or 0.38, minimum cement is 6.25 sacks/cubic yard, water reducing admixture is 4.75% ± 0.75%) or Class B (compressive strength of 4000 psi, water-to-cement ratio is 5.0 gallons/sack or 0.44, minimum cement is 5.50 sacks/cubic yard, water reducing admixture is 5.0% ± 1.0%).

<u>Leaching of calcium hydroxide</u>

Per NUREG-1557[1], leaching of calcium hydroxide from reinforced concrete becomes significant only if the concrete is exposed to flowing water. The reinforced concrete at Plant X is not exposed to flowing water. Even if reinforced concrete is exposed to flowing water, such leaching is not significant if the concrete is constructed to ensure that it is dense, well-cured, has low permeability, and that cracking is well controlled. Cracking is controlled through proper arrangement and distribution of reinforcing bars. The concrete at Plant X was designed in accordance with ACI 318-63 (per USAR Section 5.3.1 and USAR Section 5.11.3.1) and has these characteristics. Therefore, aging management is not required.

<u>Corrosion of Embedded Steel</u>

Per NUREG-1557[1], corrosion of embedded steel is not significant for concrete structures above or below grade not exposed to an aggressive environment (pH

[1] NUREG-1557, "Summary of Technical Information and Agreements from Nuclear Management and Resoures Council Industry Reports Addressing License Renewal", October 1996.

less than 11.5 or chlorides greater than 500 ppm) or for concrete structures exposed to an aggressive environment but have a low water-to-cement ratio (0.35 to 0.45), adequate air entrainment (3 to 6%), and designed in accordance with ACI 318-63 or ACI 349-85. Therefore, if these conditions are satisfied, aging management is not required. The concrete at Plant X is not exposed to aggressive river water or groundwater. There is no heavy industry in area whose emissions would cause degradation to concrete. The concrete at Plant X has been designed in accordance with ACI 201.2R that provides a low water-to-cement ratio and adequate air entrainment. The concrete mix design specified a water-to-cement ratio of 0.38 and air entrainment of 4.75% ± 0.75% for Class A concrete. It specified a water-to-cement ratio of 0.44 and air entrainment of 5.00% ± 1.00% for Class B concrete. Class C concrete was only used for radiation shields; therefore, it would not be exposed to an environment that would promote corrosion of embedded steel. The concrete at Plant X was designed in accordance with ACI 318-63 (per USAR Section 5.3.1 and USAR Section 5.11.3.1). The conditions specified above have been satisfied; therefore, aging management is not required.

Aggressive Chemical Attack

Aggressive chemical attack on reinforced concrete is not significant if the concrete is not exposed to an aggressive environment (pH less than 5.5), or to chloride or sulfate solutions beyond defined limits (greater than 500 ppm chloride, or greater than 1500 ppm sulfate). Therefore, if these conditions are satisfied, aging management is not required. The concrete at Plant X is not exposed to aggressive river water or groundwater. There is no heavy industry in area whose emissions would cause degradation to concrete or steel. The conditions specified above have been satisfied; therefore, aging management is not required.

3.5.1.2.2 Settlement and Erosion of Porous Concrete

The structures at Plant X are supported on end-bearing steel pipe piles driven to bedrock. Settlement and erosion of porous concrete subfoundation are not plausible aging mechanisms; therefore, aging management is not required.

3.5.1.2.3 Elevated Temperatures

The temperatures shall not exceed 150 deg F except for local areas that are allowed to have increased temperatures not to exceed 200 deg F. Therefore, if these conditions are satisfied, aging management is not required. Per USAR Section 2.5.2.3, the record high temperature in the vicinity of Plant X was 114 deg F in July 1936. This is below the temperature limit of 150 deg F. USAR Table 9.10-1 provides maximum building/room temperatures for the Auxiliary Building, Turbine Building, Containment, Control Room, Engine Driven Auxiliary Feedwater Pump Room, Radioactive Waste Processing Building, Chemistry and Radiation Protection Building, and Office/Cafeteria Addition. The maximum indoor plant temperature in Table 9.10-1 is 120 deg F inside the main area of Containment. This is below the temperature limit of 150 deg F. Per USAR Section 5.5.4, sleeve radiation fins and thermal sleeves (in conjunction with pipe insulation) were used to limit maximum temperature at the containment penetration sleeves to 150 deg F under operating conditions. The conditions specified above have been satisfied; therefore, aging management is not required.

3.5.1.2.4 Scaling, cracking, and spalling from freeze-thaw; expansion and cracking from reaction with aggregates

As described in NUREG-1557, freeze/thaw does not cause loss of material from reinforced concrete in foundations, and in above and below grade exterior concrete, for plants located in a geographic region of negligible weathering conditions (weathering index <100 day-inch/yr). Loss of material from such concrete is not significant at plants located in areas in which weathering conditions are severe (weathering index >500 day-inch/yr) or moderate (100-500 day-inch/yr), provided that the concrete mix design meets the air content (entrained air 3-6%) and water-to-cement ratio (0.35-0.45) specified in ACI 318-63 or ACI 349-85. These conditions are satisfied for Plant X and aging management is not required.

3.5.1.2.5 Abrasion/Cavitation

Abrasion/cavitation occurs only in concrete structures that are continuously exposed to flowing water. Abrasion/cavitation damage is not common if velocities are less than 40 fps. In closed conduits, however, degradation due to abrasion/cavitation can occur at a velocity as low as 25 fps when abrupt changes in slope or curvature exists. Therefore, if these conditions are satisfied, aging management is not required. The concrete at Plant X is not exposed to flowing water greater than 40 fps for open channel flow or 25 fps for closed conduits. The area of the plant that has the highest water velocity for open channel flow is through the circulator suction sluice gate at 5.5 fps. The area of the plant that has the highest water velocity for a closed conduit is in the warm water recirculation tunnel at 12.6 fps. Therefore, abrasion/cavitation is not a plausible aging mechanism for concrete at Plant X. Aging management is not required.

3.5.2 Components or Aging Effects that Are Not Addressed in the GALL Report

Table 3.5.2 contains Structures and Component Supports aging management review results for internal and external environments. These tables include the component types, materials, environments, aging effects requiring management, and the programs and activities for managing aging.

The following combinations of materials and environments exist for the components subject to aging management in the Structures and Component Supports.

- Structural Stainless Steel Inside Containment

- Structural Stainless Steel In Ambient Air
- Neoprene in Plant Indoor Air

3.5.2.1 Structural Stainless Steel Inside Containment

Stainless steel inside buildings is protected from the atmosphere/weather. It may be exposed to temperatures up to 120 deg F and 100% humidity. The stainless steel may be exposed to borated water during refueling.

Aging Effects Requiring Management, and Mechanisms:

Cracking

Due to stress corrosion cracking (SCC): SCC is an aging effect requiring management due to the exposure of stainless steel to halogens, sulfates, and stress.

Due to fatigue/cyclic loading: Cracking due to fatigue is an aging effect requiring management due to the progressive, localized structural change in materials subjected to fluctuating stresses and strains.

Loss of Material

Due to crevice corrosion: Loss of material due to crevice corrosion is an aging effect requiring management due to the exposure of stainless steel to dissolved oxygen.

Due to Pitting Corrosion: Loss of material due to pitting corrosion is an aging effect requiring management due to the exposure of stainless steel to halogens and sulfates.

3.5.2.2 Structural Stainless Steel In Ambient Air

This group includes stainless steel items with an external environment of plant indoor air or containment air.

Aging Effects Requiring Management, and Mechanisms:

No Aging Effects Requiring Management were identified for stainless steel in ambient air.

3.5.2.3 Neoprene in Plant Indoor Air

Neoprene inside buildings is protected from the atmosphere/weather. It may be exposed to temperatures up to 150 deg F and 100% humidity.

Aging Effects Requiring Management, and Mechanisms:

Cracking

Due to Thermal Exposure: Cracking due to thermal exposure is an aging effect requiring management due to the prolonged exposure of neoprene to temperatures above 95 deg F.

Change in Material Properties

Due to thermal exposure: A change in material properties due to thermal exposure is an aging effect requiring management due to the prolonged exposure of neoprene to temperatures above 95 deg F.

3.5.3 Conclusion

The aging effects requiring management are adequately managed by the following programs:

Chemistry Program
Containment Leak Rate Program
Structures Monitoring Program
Containment Inservice Inspection Program
Periodic Surveillance and Preventive Maintenance

These programs are described in Appendix B.

Table 3.5.2
Structures and Component Supports or Aging Effects that Are Not Addressed in the GALL Report

Component Types	Material	Environment	AERMs	Program/Activity
Trisodium Phosphate Baskets	Stainless Steel	Containment Air	None	None required
Fuel Transfer Tube	Stainless Steel	Containment Air	None	None required
Fuel Transfer Tube	Stainless Steel	Borated Water	Loss of Material Cracking	Chemistry Program Containment Leak Rate Program
Intake Flood Panel Seals	Neoprene	Plant Indoor Air	Change in Material Properties Cracking	Periodic Surveillance and Preventive Maintenance

3.6 Aging Management of Electrical and Instrumentation and Controls

The components for Plant X evaluated in this section of the application encompasses the passive, long-lived electrical cables and connections which support an intended function as defined by 10 CFR Part 54.21(a)(1)(i). Cables and their associated connectors perform the function of providing electrical energy (either continuously or intermittently) to power various equipment and components throughout the plant to enable them to perform their intended functions. Cables and connectors associated with the 10CFR50.49 program (Environmental Qualification) are addressed either as short lived, replaced periodically, or as long-lived Time Limited Aging Analysis candidates (TLAA), as such those candidates are not included in the set of cables and connectors requiring aging management review.

OPERATING EXPERIENCE:

Site: Searches were conducted of pertinent site records, including the Condition Report (CR) system, and discussions were held with appropriate site personnel. These efforts revealed no evidence of additional aging effects requiring management.

Industry: Searches were conducted of industry records. These reviews revealed no evidence of additional aging effects requiring management.

3.6.2 Aging Management Programs Evaluated in the GALL Report that Are Relied on for License Renewal

Table 3.6.1 shows the component groups (combinations of materials and environments), and aging management programs evaluated in the GALL Report that are relied on for license renewal of the Structures and Component Supports for Plant X.

Table 3.6.1
Aging Management Programs Evaluated in the GALL Report that Are Relied on for License Renewal

Component Group	Aging Effect / Mechanism	Aging Management Program	GALL Further evaluation recommended	Discussion
Non-EQ electrical cables and connections	Embrittlement, cracking, melting, discoloration, leading to reduced insulation resistance, electrical failure, caused by thermal/ thermoxidative degradation of organics, radiolysis and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation	Aging management program for Non-EQ electrical cables and connections exposed to an adverse localized environment caused by heat or radiation	No	The information in the GALL report bounds Plant X.
Non-EQ inaccessible medium-voltage (2kV to 15kV) cables (e.g., installed in conduit or direct buried)	Formation of water trees, localized damage, leading to electrical failure (breakdown of insulation), caused by moisture intrusion, water trees	Aging management program for Non-EQ inaccessible medium-voltage cables exposed to an adverse localized environment caused by moisture and voltage exposure	No	Aging management program is different from that described in GALL – see Section 3.6.1.2.1

Table 3.6.1
Aging Management Programs Evaluated in the GALL Report that Are Relied on for License Renewal

Component Group	Aging Effect / Mechanism	Aging Management Program	GALL Further evaluation recommended	Discussion
Non-EQ electrical connectors exposed to borated water leakage	Corrosion of connector contact surfaces caused by intrusion of borated water	Borated water leakage surveillance program for Non-EQ electrical connectors	No	Aging management program is different from that described in GALL – see Section 3.6.1.2.2

3.6.2.1 Further Evaluation of Aging Management as Recommended by GALL

No items requiring further evaluation were identified.

3.6.2.2 Aging Management Programs or Evaluations that Are Different from those Described in the GALL Report

3.6.2.2.1 Non-EQ inaccessible medium-voltage (2kV to 15kV) cables potentially exposed to wetting

The duct banks in which non-EQ inaccessible medium-voltage (2kV to 15kV) cables are enclosed at Plant X have been sealed to prevent water intrusion. A one-time inspection will be performed prior to the end of the current license period to ensure these duct banks remain effectively sealed.

3.6.2.2.2 Non-EQ electrical connectors exposed to borated water leakage

The inspection of electrical components at Plant X is included in the Boric Acid Corrosion Program.

3.6.3 Components or Aging Effects that Are Not Addressed in the GALL Report

No components or aging effects that are not addressed in the GALL Report were identified.

3.6.4 Conclusion

The following programs adequately manage the aging effects requiring management:

Non-EQ Electrical Cables and Connections Program
One Time Inspection Program
Boric Acid Corrosion Program

These programs are described in Appendix B.