Audit and Review Report for

Plant Aging Management Reviews and Programs

Oyster Creek Generating Station (OCGS)
Docket No.: 50-219

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Revision 1

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Audit and Review Report for Plant Aging Management Reviews and Programs For Oyster Creek Generating Station

1. Introduction and General Information

1.1 Introduction

By letter dated July 22, 2005 (Agencywide Documents Access and Management System [ADAMS] ADAMS Accession Number ML0520800480), AmerGen Energy Company, LLC, (AmerGen, the applicant) submitted to the U.S. Nuclear Regulatory Commission (NRC) its application for renewal of Facility Operating License No. DPR-16 for Oyster Creek Generating Station (ADAMS Accession Number ML052080185). The applicant requested renewal of its operating license for an additional 20 years beyond the 40-year current license term.

In support of the staff's safety review of the license renewal application (LRA) for Oyster Creek Generating Station (OCGS), the License Renewal Branch C (RLRC) led a project team that audited and reviewed selected aging management reviews (AMRs) and associated aging management programs (AMPs) developed by the applicant to support the LRA for OCGS. The project team included both NRC staff and contractor personnel provided by Brookhaven National Laboratory (BNL), the RLRC technical contractor. Attachment 2 lists the project team members, as well as other NRC staff and BNL personnel who supported the project team's audit and review.

The project team performed its work in accordance with the requirements of Title 10 of the Code of Federal Regulations (CFR), Part 54 (10 CFR Part 54), Requirements for Renewal of Operating Licenses for Nuclear Power Plants; the guidance provided in Revision 1 of NUREG-1800, Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants (SRP-LR); and the guidance provided in Revision 1 of NUREG-1801, Generic Aging Lessons Learned (GALL) Report, (GALL Report).

Details of how the project team implemented these requirements and guidance are found in "Audit and Review Plan for Plant Aging Management Reviews and Programs - Oyster Creek Generating Station," Revision 1, Docket No. 50-219, (ADAMS Accession Number ML060200084) (OCGS audit and review plan).

This audit and review report documents the results of the project team's audit and review work. The project team performed its work at NRC Headquarters, Rockville, Maryland; at Brookhaven National Laboratory offices in Upton, New York; and at the applicant's offices (OCGS site) in Forked River, New Jersey. The project team conducted on-site visits during the weeks of October 3, 2005, January 23, 2006, February 13, 2006, and April 19, 2006. The project team conducted a public exit meeting at the Lacey Township Municipal Building in Forked River, New Jersey, on April 20, 2006. Attachment 2 lists the applicant personnel and other individuals contacted by the project team in support of the work documented in this audit and review report. It also lists those attending the public exit meeting.

1.2 Background

In 10 CFR 54.4, the scope of license renewal is defined as those systems, structures, and components (SSCs) (1) that are safety-related, (2) whose failure could affect safety-related functions, or (3) that are relied on to demonstrate compliance with NRC regulations for fire protection, environmental qualification, pressurized thermal shock, anticipated transients without scram, and station blackout. An applicant for a renewed license must review all SSCs within the scope of license renewal to identify those structures and components (SCs) subject to an AMR. SCs subject to an AMR are those that perform an intended function without moving parts or without a change in configuration or properties, and that are not subject to replacement based on qualified life or specified time period. Pursuant to 10 CFR 54.21(a)(3), an applicant for a renewed license must demonstrate that the effects of aging will be managed in such a way that the intended function or functions of those SCs will be maintained for the period of extended operation.

In addition, 10 CFR 54.21(d) requires that the applicant submit a supplement to the Final Safety Analysis Report (FSAR) that contains a summary description of the programs and activities for managing the effects of aging.

The SRP-LR provides staff guidance for reviewing applications for license renewal. The GALL Report is a technical bases document. It summarizes staff-approved AMPs for the aging of a large number of SCs that are subject to an AMR. It summarizes the aging management evaluations, programs, and activities credited for managing aging for most of the SCs used by commercial nuclear power plants, and serves as a reference for both the applicant and staff reviewers to quickly identify those AMPs and activities that the staff have determined will provide adequate aging management during the period of extended operation. If an applicant commits to implementing these staff-approved AMPs, the time, effort, and resources used to review an applicant's LRA will be greatly reduced, thereby improving the efficiency and effectiveness of the license renewal review process. The GALL Report identifies (1) SSCs, (2) component materials, (3) environments to which the components are exposed, (4) aging effects/aging mechanisms associated with the materials and environments, (5) AMPs that are credited with managing the aging effects, and (6) recommendations for further applicant evaluations of aging effects and their management for certain component types.

The GALL Report is treated in the same manner as an NRC-approved topical report that is generically applicable. An applicant may reference the GALL Report in its LRA to demonstrate that its programs correspond to those that the staff reviewed and approved in the GALL Report. If the material presented in the LRA is consistent with the GALL Report and is applicable to the applicant's facility, the staff will accept the applicant's reference to the GALL Report. In making this determination, the staff considers whether the applicant has identified specific programs described and evaluated in the GALL Report but does not conduct a review of the substance of the matters described in the GALL Report. Rather, the staff determines that the applicant established that the approvals set forth in the GALL Report apply to its programs.

If an applicant takes credit for a GALL Report program, it is incumbent on the applicant to ensure that its plant program addresses all ten program elements of the referenced GALL Report program. These elements are described in the SRP-LR, Appendix A.1, "Aging Management Review - Generic (Branch Technical Position RLSB-1)." In addition, the conditions at the plant must be bounded by the conditions for which the GALL Report program was evaluated. The applicant must certify in its LRA that it completed the appropriate verifications and that those verifications are documented and retained by the applicant in an auditable form.

2. Audit and Review Scope

The AMRs and associated AMPs that the project team reviewed are identified in the OCGS audit and review plan. The project team examined 49 of the OCGS AMPs, including 11 AMPs for the Forked River Combustion Turbine (FRCT), and associated AMRs. The FRCT AMPs and AMRs are addressed in Attachment 7 to this audit and review report. The project team reviewed AMPs and AMRs that the applicant claimed were consistent with the GALL Report, and AMRs for which further evaluation is recommended by the GALL Report. The project team also reviewed certain plant-specific AMPs.

The applicant noted that some of its AMPs, although described as consistent with the GALL Report, contain some deviations from the GALL Report. These deviations are of two types:

- exceptions to the GALL Report - exceptions are specified to GALL Report recommendations that the applicant does not intend to implement.

- enhancements - enhancements include those actions/activities necessary to (1) ensure consistency with GALL Report AMP recommendations, or (2) provide additional features to the program or program activities that the applicant will implement prior to the period of extended operation. Enhancements may expand, but not reduce, the scope of an AMP.

The project team's audit and review activities for the OCGS AMPs, and its conclusions regarding these reviews, are documented in Sections 3.0.3 of this audit and review report.

The project team reviewed all OCGS LRA Table 2[1] AMR line-items in Chapter 3, except those that were assigned to the Office of Nuclear Reactor Regulation (NRR), Division of Engineering (DE) staff. Those the project team reviewed were either consistent with the GALL Report, as identified by Notes A through E in OCGS LRA Table 3.X.2-Y (from Column 9 of the Table 2s discussed in Section 3.0.1 of this audit and review report), or reviewed and accepted by the project team on the basis of an NRC-approved precedent (see Section 3.0.2.3 of this audit and review report).

The project team determined that the AMR results, reported by the applicant to be consistent with the GALL Report, are consistent with the GALL Report. The project team also determined that the plant-specific AMR results reported by the applicant are technically acceptable and applicable. For AMR results for which the GALL Report recommends further evaluation, the project team reviewed the applicant's evaluation and determined that it adequately addresses the issues for which the GALL Report recommends further evaluation.

The AMR results that are within the scope of the project team's audit are identified in Appendix D of the OCGS audit and review plan. The AMR result line-items reviewed by the project team in Chapter 3 of the OCGS LRA Tables 3.X.2-Y were either consistent with the GALL Report or justified by the applicant on the basis of an NRC-approved precedent.

In the OCGS LRA, Tables 3.X.2-Y, in addition to the notes, the applicant provided a summary of AMR results for the applicable systems, which included the SCs, associated materials, environment, any aging effects requiring management, and an AMP for each line-item. The notes describe how the information in the tables aligns with the information in the GALL Report. Those that are aligned with the GALL Report are assigned letters and are described below. Those defined by the applicant are assigned numbers and are defined in the OCGS LRA.

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[1]Table 2 provides detailed results of the AMRs for those components identified in the LRA Section 2 as being subject to an AMR.

Note A indicates that the OCGS AMR line-item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the OCGS AMP is consistent with the AMP identified in the GALL Report.

Note B indicates that the OCGS AMR line-item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the OCGS AMP takes some exceptions to the AMP identified in the GALL Report. The project team determined that the identified exceptions to the GALL Report AMPs are acceptable.

Note C indicates that the component for the OCGS AMR line-item is different, but consistent with the GALL Report for material, environment, and aging effect. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report. However, the applicant identified a different component in the GALL Report that had the same material, environment, aging effect, and AMP as the component that was under review. The project team determined that the OCGS AMR line-item of the different component was applicable to the component under review.

Note D indicates that the component for the OCGS AMR line-item is different, but consistent with the GALL Report for material, environment, and aging effect. In addition, the OCGS AMP takes some exceptions to the AMP identified in the GALL Report. The project team reviewed these line-items to confirm consistency with the GALL Report. The project team determined that the OCGS AMR line-item for the different component was applicable to the component under review. The project team determined that the identified exceptions to the GALL Report AMPs are acceptable.

Note E indicates that the OCGS AMR line-item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The project team evaluated these line-items to determine that the AMP credited by the applicant is applicable.

Note F indicates that the material is not in the GALL Report for the identified component.

Note G indicates that the environment is not in the GALL Report for the identified component and material.

Note H indicates that the aging effect is not in the GALL Report for component, material, and environment combination.

Note I indicates that the aging effect in the GALL Report for the identified component, material, and environment combination is not applicable.

Note J indicates that neither the identified component nor the material and environment combination is evaluated in the GALL Report.

Discrepancies or issues discovered by the project team during the audit and review that required a response are documented in this audit and review report. If resolution of an issue was not resolved prior to issuing this audit and review report, a request for additional information (RAI) was prepared by the project team to solicit the information needed to disposition the issue. The RAI will be included and dispositioned in the safety evaluation report (SER) related to the OCGS LRA. The list of RAIs associated with the audit and review report is provided in Attachment 4 to this audit and review report.

The project team conducted an audit and review of the information provided in the OCGS LRA and program bases documents, which are available at the applicant's office, and through interviews with OCGS technical staff. The project team determined that the applicable aging effects were identified, the appropriate combination of materials and environments were listed, and acceptable AMPs were specified.

The AMR results review of OCGS LRA Sections 3.1 through 3.6 reviewed by the project team are provided in Sections 3.1 through 3.6 of this audit and review report.

3. Aging Management Review Audit and Review Results

This section of the audit and review report contains the project team's evaluation of the OCGS AMPs and AMRs. In OCGS LRA Appendix B, the applicant described the AMPs that it relies on to manage or monitor the aging of long-lived, passive components and structures.

In OCGS LRA Section 3, the applicant provided the results of the AMRs for those structures and components that it identifies in OCGS LRA Section 2 as being within the scope of license renewal and subject to an AMR.

3.0 OCGS's Use of the Generic Aging Lessons-Learned Report

In preparing its OCGS LRA, AmerGen credited the GALL Report. The GALL Report contains the staff's generic evaluation of the existing plant programs, and it documents the technical basis for determining where existing programs are adequate without modification, and where existing programs should be augmented for the extended period of operation. The evaluation results documented in the GALL Report indicate that many of the existing programs are adequate to manage the aging effects for particular structures or components for license renewal without change. The GALL Report also contains recommendations on specific areas for which existing programs should be augmented for license renewal. OCGS references the GALL Report in its LRA to demonstrate that the programs at its facility correspond to those recommended in the GALL Report.

3.0.1 Format of the OCGS License Renewal Application

The OCGS LRA closely follows the standard LRA format presented in Nuclear Energy Institute (NEI) guidance, NEI 95-10, Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule, Revision 5.

The organization of Section 3 of the OCGS LRA parallels Chapter 3 of the SRP-LR. Section 3 of the OCGS LRA provides the results of the AMRs for SCs that the applicant identified as subject to an AMR. Organization of this section is based on Tables 1 through 6 of Volume 1 of NUREG-1801, draft dated January 2005, and Chapter 3, "Aging Management Review Results," of NUREG-1800, draft dated January 2005. The use of the draft January 2005 GALL Report is in accordance with the January 13, 2005 meeting between the NRC and NEI on updating license renewal guidance documents, as summarized and documented in a meeting summary dated February 17, 2005 (ADAMS Accession Number ML050490142).

In AmerGen letter 2130-06-20293 dated March 30, 2006 (ML060950408), the applicant summarized the results of its reconciliation of the Oyster Creek license renewal application with the guidance contained in the September 2005 Revision 1 NUREG-1800 and NUREG-1801 documents. The applicant provided details of this reconciliation in its reconciliation document, “Reconciliation of Program and Line Item Differences Between January 2005 Draft NUREG-1801 and September 2005 Revision 1 NUREG-1801,” Revision 1, (ML060870123). In its reconciliation document, the applicant identified and reconciled differences between the draft January 2005 GALL AMP and AMR line items used in the Oyster Creek LRA, with those in the September 2005 Revision 1 GALL Report. This reconciliation document was reviewed as part of this audit, and was treated as an extension of the Oyster Creek license renewal application for purposes of this audit.

OCGS LRA Tables 3.0-1 and 3.0-2, provide descriptions of the internal and external service environments that were used in the aging management reviews to determine aging effects requiring management. OCGS LRA Table 3.0-3 provides descriptions of the passive component materials, and Table 3.0-4 provides descriptions of aging effects. This table also provides the equivalent GALL Report aging effects.

The results of the AMRs are presented in two table types. The first table type is Table 3.X.1 (Table 1), where the “3" indicates the table pertaining to the Chapter 3 AMR; the ?X” indicates the table number from Volume 1 of the GALL Report (see the definition table below), and the 1 indicates that this is the first table type (Table 1) in Section 3.X. For example, in the reactor vessel, internals, and reactor coolant systems subsection, this is Table 3.1.1, and in the engineered safety features subsection, this is Table 3.2.1.

Definition Table

X	Definition
1	Reactor Vessel, Internals, and Reactor Coolant Systems
2	Engineered Safety Features
3	Auxiliary Systems
4	Steam and Power Conversion System
5	Containment, Structures, Component Supports, and Piping and Component Insulation
6	Electrical Components

The second table type is Table 3.X.2-Y, (Table 2) where “3" again indicates the OCGS LRA section number; “X” again indicates the table number from Volume 1 of the GALL Report; the “2" indicates that this is the second table type (Table 2) in Section 3.X; and “Y” indicates the system table number. For example, within the reactor vessel, internals, and reactor coolant systems subsection, the AMR results for the Isolation Condenser System are presented in Table 3.1.2.1.1, and the results for the Nuclear Boiler Instrumentation System are in Table 3.1.2.1.2. In the engineered safety features subsection, the containment spray system results are presented in Table 3.2.2.1.1, and the Core Spray System results are in Table 3.2.2.1.2.

The applicant compared the OCGS AMR results with information in the tables of the GALL Report and provided the results of its comparisons in two table types that correspond to the two table types described above.

3.0.1.1 *Overview of OCGS LRA Table 1*

OCGS LRA Table 1 provides a summary comparison of how the OCGS AMR results align with the corresponding tables of the GALL Report. OCGS LRA Table 1 consists of the following columns: “Item Number,” “Component,” “Aging Effect/Mechanism,” “AMPs,” “Further Evaluation Recommended” and “Discussion.” These OCGS LRA tables have the same format and are essentially the same as Tables 1 through 6 of the GALL Report, Volume 1, except that the “ID” and “Type” columns of the GALL Report tables were replaced by an “Item Number” column and the ?Related Generic Item” and “Unique Item” columns of the GALL Report tables were replaced by a “Discussion” column. The “Discussion” column includes further clarifying/amplifying information. The following are examples of information that are contained within the “Discussion” column:

(1) information on further evaluation required or reference to the location of that information

(2) the name of a plant-specific program being used

(3) exceptions to the GALL Report assumptions

(4) a discussion of how the line-item is consistent with the corresponding line-item in the GALL Report

(5) a discussion of how the line-item differs from the corresponding line-item in the GALL Report, when it may appear to be consistent

3.0.1.2 *Overview of OCGS LRA Table 2*

The OCGS LRA Table 3.X.2-Y (Table 2) provides the detailed results of the AMRs for those components identified in OCGS LRA Section 2 as being subject to an AMR. There is a Table 2 for each of the components or systems within a system grouping (e.g., Reactor Vessel, Internals, and Reactor Coolant Systems, Engineered Safety Features, Auxiliary Systems, etc.). For example, the Engineered Safety Features system group contains tables specific to Containment Spray System, Core Spray System, and Standby Gas Treatment System. Table 2 consists of the following nine columns:

(1) *Component Type* – The first column identifies the component types that are subject to an AMR. The component types are listed in alphabetical order. In the structural tables, component types are sub-grouped by material.

(2) *Intended Function* – The second column identifies the license renewal intended functions for the listed component types. Definitions and abbreviations of intended functions are listed in Table 2.1-1 in Section 2 of the OCGS LRA.

(3) *Material* – The third column lists the particular materials of construction for the component type being evaluated.

(4) *Environment* – The fourth column lists the environment to which the component types are exposed. Internal and external service environments are indicated. A description of these environments is provided in Table 3.0-1 and Table 3.0-2, for mechanical, structural, and electrical components, respectively.

(5) *Aging Effect Requiring Management* – The fifth column lists the aging effects identified as requiring management for the material and environment combinations of each component type.

(6) *Aging Management Programs* – The sixth column lists the programs used to manage the aging effects requiring management.

(7) *NUREG-1801 Volume 2 Item* – The seventh column documents identified consistencies of factors listed in Table 2 of the OCGS LRA with the GALL Report by noting the appropriate GALL Report AMR line-item. Each combination of the following factors listed in Table 2 is compared to the GALL Report to identify those consistencies: component type, material, environment, aging effect requiring management, and AMP. If there is no corresponding AMR line-item in the GALL Report for a particular combination of factors, Column 7 is left blank.

(8) *Table 1 Item* – The eighth column is a cross reference of line-items from Table 2 to Table 1. Each combination of the following that has an identified GALL Report AMR line-item also has a Table 1 line-item reference number: component type, material, environment, aging effect requiring management, and AMP. Column 8 lists the corresponding line-item from Table 1. If there is no corresponding item in the GALL Report Volume 1, Column 8 is left blank.

(9) *Notes* – The ninth column contains notes that are used to describe the degree of consistency with the AMR line-items in the GALL Report. Notes that use letter designations are standard notes based on the letter from A. Nelson, NEI, to P.T. Kuo, NRC, "U.S. Nuclear Industry's Proposed Standard License Renewal Application Format Package, Request NRC Concurrence," dated January 24, 2003 (ML030290201). (Note that the staff concurred in the format of the standardized format for LRAs by letter dated April 7, 2003, from P.T. Kuo, NRC, to A. Nelson, NEI [ML030990052].) Notes that use numeric designators are specific to OCGS. The letter notes are described in detail in Section 2 of this audit and review report.

3.0.2 Audit and Review Process

The project team performed the audit and review in accordance with the criteria defined in Revision 1 of NUREG-1800, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants (SRP-LR).” Additional details on how the SRP-LR criteria were addressed are provided in the OCGS audit and review plan. This review process is summarized in this section.

3.0.2.1 *Review of the OCGS AMPs*

For the OCGS AMPs for which the applicant claimed consistency with the AMPs in the GALL Report, the project team determined consistency. The project team determined reviewed the OCGS AMP descriptions and compared the ten program elements for those AMPs to the corresponding program elements for the GALL Report AMPs (Attachment 3 shows the ten aging management program elements from the SRP-LR). The Division of Engineering (DE) reviewed and determined the adequacy of the applicant's 10 CFR Part 50, Appendix B Program and the results documented in Section 3 of the safety evaluation report (SER) related to the OCGS LRA.

For the OCGS AMPs that have one or more exceptions and/or enhancements, the project team reviewed each exception and/or enhancement to determine whether the exception and/or enhancement is acceptable, and whether the OCGS AMP, as modified by the exception and/or enhancement, would adequately manage the aging effects for which it is credited. In some cases, the project team identified differences that the applicant did not identify between the OCGS AMPs credited by the applicant and the GALL Report AMPs. In these cases, the project team reviewed the difference to determine whether or not it is acceptable, and whether or not the AMP, as modified by the difference, would adequately manage the aging effects.

For those OCGS AMPs that are not included in the GALL Report, the project team reviewed the OCGS AMP against the program elements specified in Appendix A.1 of the SRP-LR. The project team determined whether these OCGS AMPs would manage the aging effects for which they are credited.

3.0.2.2 *Review of the OCGS AMR Results*

The AMRs in the GALL Report fall into two broad categories:

- those the GALL Report concludes are adequate to manage aging of the components referenced in the GALL Report, and

- those for which the GALL Report concludes that further evaluation is recommended for certain aspects of the aging management process.

The project team determined that the OCGS AMR results, reported by the applicant to be consistent with the GALL Report, are consistent with the GALL Report. The project team also determined that the plant-specific AMR results reported by the applicant are technically acceptable and applicable. For AMR results for which the GALL Report recommends further evaluation, the project team reviewed the applicant's evaluation to determine whether it adequately addresses the issues for which the GALL Report recommended further evaluation.

3.0.2.3 *NRC-Approved Precedents*

To help facilitate the staff's review of its LRA, an applicant may reference NRC-approved precedents to demonstrate that its non-GALL programs correspond to reviews that the NRC has approved for other plants during its review of previous applications for license renewal. When an applicant elected to provide precedent information, the project team determined whether the material presented in the precedent was applicable to the applicant's facility, determined whether the plant program was bounded by the conditions for which the precedent was evaluated and approved, and determined that the plant program contained the program elements of the referenced precedent. In general, if the project team determined that these conditions were satisfied, it used the information in the precedent to frame and focus its review of the applicant's program.

It is important to note that precedent information is not a part of the LRA; it is supplementary information voluntarily provided by the applicant as a reviewer's aid. The existence of a precedent, in and of itself, is not a sufficient basis to accept the applicant's program. Rather, the precedent facilitates the review of the substance of the matters described in the applicant's program. As such, in the applicant's documentation of its programs that are based on precedents, the precedent information is typically implicit in the evaluation rather than explicit. If the project team determined that a precedent identified by the applicant is not applicable to the particular plant program for which it is credited, it may have referred the program to NRR/DE for review in the traditional manner, i.e., as described in the SRP-LR, without consideration of the precedent information.

AmerGen chose not to use precedent information to support its selection of OCGS aging management programs.

3.0.2.4 *Updated Final Safety Analysis Review Supplement*

Consistent with the SRP-LR, for the AMR results and associated AMPs that it reviewed, the project team also reviewed the Updated Final Safety Analysis Review (UFSAR) supplement that summarizes the applicant's programs and activities for managing the effects of aging for the period of extended operation, as required by 10 CFR 54.21(d).

3.0.2.5 *Documentation and Documents Reviewed*

In performing its work, the project team relied heavily on the OCGS LRA, the SRP-LR, and the GALL Report. The project team also reviewed the applicant's AMP bases documents (a catalog of the documentation used by the applicant to develop or justify its AMPs), and other on-site documents, including selected implementing documents, to determine whether the applicant's activities and programs will adequately manage the effects of aging on SCs.

Any discrepancies or issues discovered during the audit and review that required a formal response on the docket are documented in this audit and review report. If an issue was not docketed or was not resolved prior to issuing this audit and review report, an RAI was prepared by the project team describing the issue and the information needed to disposition the issue. The RAI, if needed, is included and dispositioned in the SER related to the OCGS LRA. The list of RAIs associated with the audit and review is provided in Attachment 4 to this audit and review report.

Attachment 5 characterizes the nature and extent of the project team's reviews of the applicant's documents, and lists the documents reviewed by the project team. During its audit and review, the project team also conducted detailed discussions and interviews with the applicant's license renewal project personnel and other personnel with technical expertise relevant to aging management.

3.0.2.6 *Commitments To Be Included in the Safety Evaluation Report*

During the audit and review, the project team requested additional information to resolve issues related to the content of the LRA. In responding to these requests for additional information, the applicant, in some cases, committed to supplement its LRA to correct entries or implement additional activities, as needed, to appropriately manage aging of the various SSCs within the scope of license renewal. A list of these commitments is included in Attachment 6 of this audit and review report.

3.0.2.7 *Exit Meeting*

The project team held a public exit meeting with the applicant on April 20, 2006, to discuss the results of its audit and review of the AMPs and AMR results assigned to the project team. These discussions reflected the project team's work and its results, as documented in this audit and review report.

3.0.3 OCGS Aging Management Programs

The project team's audit and review activities for the OCGS AMPs and its conclusions regarding these programs are documented below. The audit and review was performed in accordance with the guidance contained in the OCGS audit and review plan, as summarized in Section 3.0.2 of this audit and review report.

Table 3.0.3-1, OCGS Aging Management Programs, presents the AMPs credited by the applicant and described in Appendix B of the LRA. The table also indicates the SSCs that credit the AMPs and the GALL AMP from which the applicant claimed consistency. The section of the audit and review report in which the project team's evaluation of the program is documented also is provided.

Table 3.0.3-1 OCGS Aging Management Programs (1)

OCGS AMP (LRA Section)	GALL Report Comparison	GALL Report AMP(s)	OCGS LRA Systems or Structures that Credit the AMP	Project Team's Evaluation Section
ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.1.1)	Consistent with exception and enhancement	XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Reactor Vessel, Internals, and Reactor Coolant Sys. Engineered Safety Features Auxiliary Systems Steam and Power Conversion System	3.0.3.2.1

OCGS AMP (LRA Section)	GALL Report Comparison	GALL Report AMP(s)	OCGS LRA Systems or Structures that Credit the AMP	Project Team's Evaluation Section
Water Chemistry (B.1.2)	Consistent with exceptions	XI.M2, Water Chemistry	Reactor Vessel, Internals, and Reactor Coolant Systems Engineered Safety Features Auxiliary Systems	3.0.3.2.2
Reactor Head Closure Studs (B.1.3)	Consistent with exception	XI.M3, Reactor Head Closure Studs	Reactor Vessel, Internals, and Reactor Coolant Systems	3.0.3.2.3
BWR Vessel ID Attachment Welds (B.1.4)	Consistent with exceptions	XI.M4, BWR Vessel ID Attachment Welds	Reactor Vessel, Internals, and Reactor Coolant Systems	3.0.3.2.4
BWR Feedwater Nozzle (B.1.5)	Consistent with exception and enhancement	XI.M5, BWR Feedwater Nozzle	Reactor Vessel, Internals, and Reactor Coolant Systems	3.0.3.2.5
BWR Control Rod Drive Return Line Nozzle (B.1.6)	Consistent with exceptions	XI.M6, BWR Control Rod Drive Return Line Nozzle	Reactor Vessel, Internals, and Reactor Coolant Systems	3.0.3.2.6
BWR Stress Corrosion Cracking (B.1.7)	Consistent with exceptions (3) and enhancement(2)	XI.M7, BWR Stress Corrosion Cracking	Reactor Vessel, Internals, and Reactor Coolant Systems	3.0.3.2.7
BWR Penetrations (B.1.8)	Consistent with exception	XI.M8, BWR Penetrations	Reactor Vessel, Internals, and Reactor Coolant Systems	3.0.3.2.8
BWR Vessel Internals (B.1.9)	Consistent with exceptions and enhancements	XI.M9, BWR Vessel Internals	Reactor Vessel, Internals, and Reactor Coolant Systems	3.0.3.2.9
Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) (B.1.10)	Consistent	XI.M13, Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)	Reactor Vessel, Internals, and Reactor Coolant Systems	3.0.3.1.1
Flow- Accelerated Corrosion (B.1.11)	Consistent	XI.M17, Flow-Accelerated Corrosion	Reactor Vessel, Internals, and Reactor Coolant Systems Engineered Safety Features Steam and Power Conversion System	3.0.3.1.2

OCGS AMP (LRA Section)	GALL Report Comparison	GALL Report AMP(s)	OCGS LRA Systems or Structures that Credit the AMP	Project Team's Evaluation Section
Bolting Integrity (B.1.12)	Consistent with exceptions	XI.M18, Bolting Integrity	Reactor Vessel, Internals, and Reactor Coolant Systems Engineered Safety Feature Systems Auxiliary Systems Steam and Power Conversion System	3.0.3.2.10
Open-Cycle Cooling Water System (B.1.13)	Consistent with enhancements	XI.M20, Open-Cycle Cooling Water System	Auxiliary Systems	3.0.3.2.11
Closed-Cycle Cooling Water System (B.1.14)	Consistent with exception	XI.M21, Closed-Cycle Cooling Water System	Auxiliary Systems Steam and Power Conversion System	3.0.3.2.12
Boraflex Rack Management Program (B.1.15)	Consistent with exception	XI.M22, Boraflex Monitoring	Auxiliary Systems	3.0.3.2.13
Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.1.16)	Consistent with exceptions(3) and enhancements	XI.M23, Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Auxiliary Systems	3.0.3.2.14
Compressed Air Monitoring (B.1.17)	Consistent	XI.M24, Compressed Air Monitoring	Auxiliary Systems	3.0.3.1.3
BWR Reactor Water Cleanup System (B.1.18)	Consistent with exception	XI.M25, BWR Reactor Water Cleanup System	Reactor Vessel, Internals, and Reactor Coolant Systems	3.0.3.2.15
Fire Protection (B.1.19)	Consistent with exception and enhancements	XI.M26, Fire Protection	Auxiliary Systems	3.0.3.2.16
Fire Water System (B.1.20)	Consistent with enhancements	XI.M27, Fire Water System	Auxiliary Systems	3.0.3.2.17
Aboveground Outdoor Tanks (B.1.21)	Consistent with exception	XI.M29, Aboveground Carbon Steel Tanks	Auxiliary Systems	3.0.3.2.18
Fuel Oil Chemistry (B.1.22)	Consistent with exceptions (2) and enhancements	XI.M30, Fuel Oil Chemistry	Auxiliary Systems	3.0.3.2.19

OCGS AMP (LRA Section)	GALL Report Comparison	GALL Report AMP(s)	OCGS LRA Systems or Structures that Credit the AMP	Project Team's Evaluation Section
Reactor Vessel Surveillance (B.1.23)	Consistent with enhancement	XI.M31, Reactor Vessel Surveillance	Reactor Vessel, Internals, and Reactor Coolant Systems	3.0.3.2.20
One-Time Inspection (B.1.24)	Consistent with exceptions (2)	XI.M32, One-Time Inspection	Reactor Vessel, Internals, and Reactor Coolant Systems Engineered Safety Feature Systems Auxiliary Systems Steam and Power Conversion Systems Containment, Structures and Component Supports	3.0.3.1.4
Selective Leaching of Materials (B.1.25)	Consistent	XI.M33, Selective Leaching of Materials	Reactor Vessel, Internals, and Reactor Coolant Systems Engineered Safety Feature Systems Auxiliary Systems	3.0.3.1.5
Buried Piping Inspection (B.1.26)	Consistent with exceptions and enhancements	XI.M34, Buried Piping and Tanks Inspection	Auxiliary Systems	3.0.3.2.21
ASME Section XI, Subsection IWE (B.1.27)	Consistent with exception	XI.S1, ASME Section XI, Subsection IWE	Reactor Vessel, Internals, and Reactor Coolant Sys. Engineered Safety Features Auxiliary Systems Steam and Power Conversion System	3.0.3.2.22
ASME Section XI, Subsection IWF (B.1.28)	Consistent with exception and enhancements	XI.S3, ASME Section XI, Subsection IWF	Containment Structures and Component Supports	3.0.3.2.23
10 CFR Part 50, Appendix J (B.1.29)	Consistent	XI.S4, 10 CFR Part 50, Appendix J	Containment, Structures and Component Supports	3.0.3.1.6
Masonry Wall Program (B.1.30)	Consistent	XI.S5, Masonry Wall Program	Containment, Structures and Component Supports	3.0.3.1.7

OCGS AMP (LRA Section)	GALL Report Comparison	GALL Report AMP(s)	OCGS LRA Systems or Structures that Credit the AMP	Project Team's Evaluation Section
Structures Monitoring Program (B.1.31)	Consistent with exceptions (2) and enhancement(2)	XI.S6, Structures Monitoring Program	Reactor Vessel, Internals, and Reactor Coolant Systems Engineered Safety Features Auxiliary Systems Steam and Power Conversion System Containment, Structures and Component Supports	3.0.3.2.24
RG 1.127, Inspection of Water-Control Structures Associated With Nuclear Power Plants (B.1.32)	Consistent with enhancements	XI.S7, RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	Containment, Structures and Component Supports	3.0.3.2.25
Protective Coating Monitoring and Maintenance Program (B.1.33)	Consistent	XI.S8, Protective Coating Monitoring and Maintenance Program	Containment, Structures and Component Supports	3.0.3.1.8
Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.1.34)	Consistent	XI.E1, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Components and Systems	3.0.3.1.9
Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (B.1.35)	Consistent with enhancements	XI.E2, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Electrical Components and Systems	3.0.3.2.26
Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.1.36)	Consistent with enhancement(2)	XI.E3, Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Components and Systems	3.0.3.1.10

OCGS AMP (LRA Section)	GALL Report Comparison	GALL Report AMP(s)	OCGS LRA Systems or Structures that Credit the AMP	Project Team's Evaluation Section
Periodic Testing of Containment Spray Nozzles (B.2.1)	N/A	Oyster Creek plant-specific program	Engineered Safety Features Systems	3.0.3.3.1
Lubricating Oil Monitoring Activities (B.2.2)	N/A	Oyster Creek plant-specific program	Auxiliary Systems	3.0.3.3.2
Generator Stator Water Chemistry Activities (B.2.3)	N/A	Oyster Creek plant-specific program	Auxiliary Systems	3.0.3.3.3
Periodic Inspection of Ventilation Systems (B.2.4)	N/A	Oyster Creek plant-specific program	Engineered Safety Features Systems Auxiliary Systems	3.0.3.3.4
Periodic Inspection Program (B.2.5)	N/A	Oyster Creek plant-specific program	Steam and Power Conversion System	3.0.3.3.5
Wooden Utility Poles Program (B.2.6)	N/A	Oyster Creek plant-specific program	Electrical Components and Systems	3.0.3.3.6
Periodic Monitoring of Combustion Turbine Power Plant (B.2.7)	N/A	NA	None – this AMP was deleted by the applicant.	3.0.3.3.7
Metal Fatigue of Reactor Coolant Pressure Boundary (B.3.1)	Consistent with enhancements	X.M1, Metal Fatigue of Reactor Coolant Pressure Boundary	Reactor Vessel, Internals, and Reactor Coolant Systems	3.0.3.2.27
Environmental Qualification (EQ) Program (B.3.2)	Consistent	X.E1, Environmental Qualification (EQ) of Electrical Components	Electrical Components and Systems	3.0.3.1.11

Notes: (1) Aging management programs for the Oyster Creek station blackout system Forked River combustion turbine power plant, radio communications systems, and meteorological tower are addressed in Attachment 7 to this audit and review report.

(2) Exception(s) and/or enhancement(s) were added based on the applicant's reconciliation of the aging management programs in the draft January 2005 GALL Report with the approved September 2005 GALL Report.

(3) Exception(s) and/or enhancement(s) were deleted based on the applicant's reconciliation of the aging management programs in the draft January 2005 GALL Report with the approved September 2005 GALL Report.

3.0.3.1 *OCGS AMPs That Are Consistent with the GALL Report*

3.0.3.1.1 Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (OCGS AMP B.1.10)

In the OCGS LRA, Appendix B, Section B.1.10, the applicant stated that OCGS AMP B.1.10, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)," is a new plant program that will be consistent with GALL AMP XI.M13, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)."

3.0.3.1.1.1 Program Description

The applicant stated, in the OCGS LRA, that this program will provide for aging management of CASS reactor internal components within the scope of license renewal. The program will be implemented prior to the period of extended operation.

The applicant also stated that the program will include a component specific evaluation of the loss of fracture toughness. A supplemental inspection will be performed for those components where loss of fracture toughness may affect the function of the component, using the criteria provided in GALL AMP XI.M13. This inspection will ensure the integrity of the CASS components exposed to the high temperature and neutron fluence present in the reactor environment.

3.0.3.1.1.2 Consistency with the GALL Report

In OCGS LRA, the applicant stated that OCGS AMP B.1.10 is consistent with GALL AMP XI.M13.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.10, including PBD-AMP-B.1.10, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel," Rev. 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M13. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.10 and associated bases documents to determine their consistency with GALL AMP XI.M13.

The project team reviewed those portions of the applicant's Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) for which the applicant claims consistency with GALL AMP XI.M13 and found that they are consistent with this GALL Report AMP. The project team found that the applicant's Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) program conforms to the recommended GALL AMP XI.M13.

3.0.3.1.1.3 Exceptions to the GALL Report

None

3.0.3.1.1.4 Enhancements

None

3.0.3.1.1.5 Operating Experience

The applicant stated, in the OCGS LRA, that the aging management program for Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) is a new program, and therefore, no programmatic operating experience exists.

In PBD B.1.10, the applicant stated that research data on both laboratory-aged and service-aged materials has confirmed that loss of fracture toughness could occur in some reactor vessel CASS internal components. Oyster Creek internal reactor vessel CASS components are periodically examined, but no degradation has been identified to date. Since the thermal aging and neutron irradiation embrittlement of CASS aging management program is a new program, a review of plant operating experience cannot confirm at this time that loss of fracture toughness of cast austenitic stainless steel is a factor.

The Oyster Creek thermal aging and neutron irradiation embrittlement of CASS aging management program will include a component specific evaluation to assess the susceptibility for the loss of fracture toughness. This evaluation will be performed prior to the period of extended operation. A supplemental inspection will be performed for those components where loss of fracture toughness may affect function of the component, using the criteria provided in NUREG-1801 Aging Management Program, XI.M13. This inspection will ensure the integrity of the CASS components exposed to the high temperature and neutron fluence present in the reactor environment.

The project team also reviewed the operating experience provided in the basis document, and interviewed the applicant's technical staff to conclude that no industry operating experience with thermal aging and embrittlement of CASS has emerged.

The staff believes that the corrective action process will capture internal and external plant operating issues to ensure that aging effects are adequately managed.

3.0.3.1.1.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the thermal aging and neutron irradiation embrittlement of cast austenitic stainless steel (CASS) program in OCGS LRA, Appendix A, Section A.1.10, which states that the thermal aging and neutron irradiation embrittlement of cast austenitic stainless steel (CASS) program is a new program that will provide for aging management of CASS reactor internal components within the scope of license renewal.

The applicant also stated that the program will be implemented prior to the period of extended operation. The program will include a component specific evaluation of the loss of fracture toughness in accordance with the criteria specified in GALL AMP XI.M13. For those components where loss of fracture toughness may affect function of the component, a supplemental inspection will be performed. This inspection will ensure the integrity of the CASS components exposed to the high temperature and neutron fluence present in the reactor environment.

The project team also reviewed the applicant’s license renewal commitment list in Appendix A of the OCGS LRA, and confirmed that this program is identified as a new program that will be implemented prior to the period of extended operation as item 10 of the commitments.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.10, found that it was consistent with the GALL Report, and determined that it provided an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.1.1.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team determined that all the program elements are consistent with the GALL Report. On the basis of its review of the UFSAR Supplement for this program, the project team found that it provided an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.2 Flow-Accelerated Corrosion (OCGS AMP B.1.11)

In OCGS LRA, Appendix B, Section B.1.11, the applicant stated that OCGS AMP B.1.11, "Flow-Accelerated Corrosion," is an existing plant program that is consistent with GALL AMP XI.M17, “Flow-Accelerated Corrosion."

3.0.3.1.2.1 Program Description

The applicant stated, in the OCGS LRA, that this program is based on EPRI guidelines in NSAC-202L-R2, “Recommendations for an Effective Flow Accelerated Corrosion Program,” April 1999. The program predicts, detects, and monitors wall thinning in piping, fittings, valve bodies, and feedwater heaters due to Flow-Accelerated Corrosion (FAC).

The applicant also stated that analytical evaluations and periodic examinations of locations that are most susceptible to wall thinning due to FAC are used to predict the amount of wall thinning in pipes, fittings, and feedwater heater shells. Program activities include analyses to determine critical locations, baseline inspections to determine the extent of thinning at these critical locations, and follow-up inspections to confirm the predictions. Inspections are performed using ultrasonic, radiographic, visual or other approved testing techniques capable of detecting wall thinning. Repairs and replacements are performed as necessary.

3.0.3.1.2.2 Consistency with the GALL Report

In OCGS LRA, the applicant stated that OCGS AMP B.1.11 is consistent with GALL AMP XI.M17.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.11, including program basis document PBD-AMP-B.1.11,"Flow-Accelerated Corrosion,” Rev. 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M17. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.11 and associated bases documents to determine consistency with GALL AMP XI.M17.

Also, the project team reviewed OCGS document Number ER-AA-430, “Conduct of FAC Activities,” Revision 1, which is a procedure for establishing, controlling, updating, and documenting FAC programs.

The project team reviewed those portions of the applicant's Flow-Accelerated Corrosion program for which the applicant claims consistency with GALL AMP XI.M17 and found that they are consistent with this GALL Report AMP. The project team found that the applicant's Flow-Accelerated Corrosion program conforms to the recommended GALL AMP XI.M17.

3.0.3.1.2.3 Exceptions to the GALL Report

None

3.0.3.1.2.4 Enhancements

None

3.0.3.1.2.5 Operating Experience

The applicant stated, in the OCGS LRA, that operating experience of Flow-Accelerated Corrosion aging management program activities has shown that the program can determine susceptible locations for flow accelerated corrosion, can predict the component degradation, and can detect the wall thinning in piping, valves, and other components (such as the feedwater heater shells) due to flow-accelerated corrosion. In addition, the program provides for reevaluation, repair or replacement for locations where calculations indicate an area will reach minimum allowable thickness before the next inspection. Periodic self assessments of the program have been performed which have identified opportunities for program improvements. In 2000, inspections of the "C" feedpump minimum recirculation line showed that several 90-degree elbows experienced significant wear. Similar wear was found on several 45-degree elbows. As a result of these inspections, approximately 25 feet of 4" pipe, one 90-degree elbow, and three 45-degree elbows were replaced with chrome-moly material.

The applicant stated in the basis document that during Cycle 17, UT Inspections were performed on the high-pressure (HP) feedwater heater (FWH) shells. These inspections were driven by the Point Beach FWH shell rupture event and other industry experience as described in SEN 199, "Feedwater Heater Shell Rupture," and NRC Information Notice (IN) 99-19, "Rupture of the Shell Side of a Feedwater Heater at the Point Beach Nuclear Plant." Results of the inspections showed wall thinning on all three HP FWH shells. Two areas on the "A" HP FWH required immediate repair. Other identified degradation was evaluated and determine to be acceptable through the remainder of the operating cycle at which time further inspections and repairs were performed. There have been a number of steam leaks associated with flash tank and drain tank piping and attached piping. However, there have been some cases where leaks did occur that were not predicted. As a result of these pipe failures, the FAC program was modified to more accurately predict that wall thinning was occurring. The experience at Oyster Creek with the FAC program shows that the FAC program is effective in managing FAC in high-energy carbon steel piping and components. Two deficiencies in the program were identified: 1) The System Susceptibility Evaluation did not meet EPRI or procedural recommendations and 2) plant model input to the FAC Program software tool, CHECWORKS, contained a number of errors and omissions. These deficiencies were identified as the primary reasons the FAC program has missed identifying components that developed leaks as a result of Flow Accelerated Corrosion. A FAC program improvement project was implemented to correct the deficiencies. The project was completed during August 2003. As a result of the improvement project, the risk of a FAC failure in unidentified susceptible lines has been reduced.

The project team recognized that the corrective action program, which captures internal and external plant operating experience issues, will ensure that operating experience is reviewed and incorporated in the future to provide objective evidence to support the conclusion that the effects of aging are adequately managed.

The project team also reviewed the operating experience provided in the OCGS LRA, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant's Flow-Accelerated Corrosion program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.1.2.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the Flow-Accelerated Corrosion program in OCGS LRA, Appendix A, Section A.1.11, which states that the Flow-Accelerated Corrosion program is an existing program based on EPRI guidelines in NSAC-202L-R2, "Recommendations for an Effective Flow Accelerated Corrosion Program," April 1999. The program predicts, detects, and monitors wall thinning in piping, fittings, valve bodies, and Feedwater Heaters due to FAC. Analytical evaluations and periodic examinations of locations that are most susceptible to wall thinning due to FAC are used to predict the amount of wall thinning in pipes, fittings, and Feedwater Heater shells. Program activities include analyses to determine critical locations, baseline inspections to determine the extent of thinning at these critical locations, and follow-up inspections to confirm the predictions. Repairs and replacements are performed as necessary.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.11, found that it was consistent with the GALL Report, and determined that it provided an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.1.2.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team determined that all the program elements are consistent with the GALL Report. On the basis of its review of the UFSAR Supplement for this program, the project team found that it provided an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.3 Compressed Air Monitoring (OCGS AMP B.1.17)

In OCGS LRA, Appendix B, Section B1.17, the applicant stated that OCGS AMP B1.17, "Compressed Air Monitoring," is an existing plant program that is consistent with GALL AMP XI.M24, "Compressed Air Monitoring."

3.0.3.1.3.1 Program Description

In the OCGS LRA, the applicant stated that this program is within the specified limits for the portions of the instrument air system within the scope of license renewal. Activities consist of yearly air quality monitoring, pressure decay testing at intervals not exceeding five years and visual inspections. The activities are consistent with the Oyster Creek response to NRC Generic Letter (GL) 88-14, “Instrument Air Supply Problems” and utilize guidance and standards provided by INPO SOER 88-01, EPRI TR-108147 and ASME OMS/ G-1998, Part 17. Testing and monitoring activities are implemented through station procedures.

3.0.3.1.3.2 Consistency with the GALL Report

In OCGS LRA, the applicant stated that OCGS AMP B1.17 is consistent with GALL AMP XI.M24.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B1.17, including program basis document PBD-AMP-B.1.17,“Compressed Air Monitoring,” Rev. 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M24. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B1.17 and associated bases documents to determine their consistency with GALL AMP XI.M24.

The project team also reviewed SDBD-0C-852, Rev. 3. “Plant Compressed Air System Design Basis Document,” and the applicant’s responses to GL 88-14 to determine consistency with GALL AMP XI.M24.

The project team reviewed those portions of the applicant’s Compressed Air Monitoring aging management program for which the applicant claims consistency with GALL AMP XI.M24 and found that they are consistent with this GALL Report AMP. The project team found that the applicant’s Compressed Air Monitoring aging management program conforms to the recommended GALL AMP XI.M24.

3.0.3.1.3.3 Exceptions to the GALL Report

None.

3.0.3.1.3.4 Enhancements

None.

3.0.3.1.3.5 Operating Experience

In the OCGS LRA, the applicant stated that the reliability of the Oyster Creek instrument air system has improved since the implementation of GL 88-14 activities and industry guidance. The Compressed Air Monitoring program has implemented new industry air quality standard, ISA-S7.0.01-1996, consistent with NUREG-1801 and replacement dryers have increased air quality as indicated by air quality test results and dewpoint monitoring

In its design basis document for the Compressed Air Monitoring aging management program (PDB-AMP-B.1.17), the applicant stated that operating experience, both internal and external, is used to enhance plant programs, prevent repeat events, and prevent events that have occurred at other plants from occurring at Oyster Creek. The applicant further stated that its process for managing programs requires the review of program related operating experience by the program owner. External operating experience may include such things as INPO documents (e.g., SOERs, SERs, SENs, etc.), NRC documents (e.g., GLs, LERs, INs, etc.), General

Electric documents (e.g., RCSILs, SILs, TILs, etc.), and other documents (e.g., 10 CFR Part 21 Reports, NERs, etc.). Internal operating experience may include such things as event investigations, trending reports, and lessons learned from in-house events as captured in program notebooks, self-assessments, and in the 10 CFR Part 50, Appendix B corrective action process. Issues and events, whether external or plant-specific, that are potentially significant to the Compressed Air Monitoring program at OCGS are evaluated. The Compressed Air Monitoring program is augmented, as appropriate, if these evaluations show that program changes are needed to enhance program effectiveness.

The applicant stated in PDB-AMP-B.1.17 that operating experience of GL 88-14 activities did not show any adverse trend in performance. In the OCGS LRA, the applicant stated that, consistent with NUREG 1801, the Compressed Air Monitoring program has implemented new industry air quality standard, ISAS7.0.01- 1996, and replacement dryers have increased air quality as indicated by air quality test results and dew point monitoring.

The project team also reviewed the operating experience provided in the OCGS LRA, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant’s Compressed Air Monitoring program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.1.3.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the Compressed Air Monitoring program in OCGS LRA, Appendix A, Section A.1.17, which states that the Compressed Air Monitoring aging management program is an existing program that consists of inspection, monitoring, and testing; including (1) pressure decay testing and visual inspections of system components; and (2) preventive monitoring that checks air quality at various locations in the system to ensure that dew point, particulates, and suspended hydrocarbons are kept within the specified limits. This program is consistent with responses to NRC GL 88-14 and incorporates ISA-S7.0.01-1996, "Quality Standard for Instrument Air."

The project team reviewed the UFSAR Supplement OCGS AMP B1.17, found that it was consistent with the GALL Report, and determined that it provided an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.1.3.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team that all the program elements are consistent with the GALL Report. . On the basis of its review of the UFSAR Supplement for this program, the project team found that it provided an adequate summary description of the program, as required by 10 CFR 54.21(d)

3.0.3.1.4 One-Time Inspection (OCGS AMP B.1.24)

In OCGS LRA, Appendix B, Section B.1.24, the applicant stated that OCGS AMP B.1.24, "One-Time Inspection," is a new plant program that will be consistent with GALL AMP XI.M32, "One-Time Inspection."

3.0.3.1.4.1 Program Description

In the OCGS LRA, the applicant stated that this program will provide reasonable assurance that an aging effect is not occurring, or that the aging effect is occurring slowly enough to not affect the component or structure intended function during the period of extended operation, and therefore will not require additional aging management. The program will be credited for cases where either (a) an aging effect is not expected to occur but there is insufficient data to completely rule it out, (b) an aging effect is expected to progress very slowly in the specified environment, but the local environment may be more adverse than that generally expected, or (c) the characteristics of the aging effect include a long incubation period. This program will be used for the following:

- To confirm crack initiation and growth due to stress corrosion cracking (SCC), intergranular stress corrosion cracking (IGSCC), or thermal and mechanical loading is not occurring in Class 1 piping less than or equal to four inches nominal pipe size (NPS 4) exposed to reactor coolant.

- To confirm the effectiveness of the water chemistry program to manage the loss of material and crack initiation and growth aging effects.

- To confirm the effectiveness of the closed cycle cooling water system program to manage the loss of material aging effect.

- To confirm the effectiveness of the fuel oil chemistry program and lubricating oil monitoring activities program to manage the loss of material aging effect.

- To confirm loss of material in stainless steel piping, piping components, and piping elements is insignificant in an intermittent condensation (internal) environment.
- To confirm loss of material in steel piping, piping components, and piping elements is insignificant in an indoor air (internal) environment.

- To confirm loss of material is insignificant for non-safety-related (NSR) piping, piping components, and piping elements of vents and drains, floor and equipment drains, and other systems and components that could contain a fluid, and are in scope for 10 CFR 54.4(a)(2) for spatial interaction. The scope of the program consists of only those systems not covered by other aging management activities.

The applicant also stated that the new program elements include:

- Determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience.

- Identification of the inspection locations in the system or component based on the aging effect.

- Determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined.

- Evaluation of the need for follow-up examinations to monitor the progression of aging if age related degradation is found that could jeopardize an intended function before the end of the period of extended operation. When evidence of an aging effect is revealed by a one-time inspection, the engineering evaluation of the inspection results would identify appropriate corrective actions.

The applicant further stated that the inspection sample includes “worse case” one-time inspection of more susceptible materials in potentially more aggressive environments (e.g., low or stagnant flow areas) to manage the effects of aging. Examination methods will include visual examination, VT-1 or VT-3 as appropriate, or volumetric examinations. Acceptance criteria is based on ASME Section XI, for components required to meet ASME requirements, and on the design code of record and industry guidelines for non-ASME components.

The one-time inspection aging management program will be implemented prior to the period of extended operation.

3.0.3.1.4.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.24 is consistent with GALL AMP XI.M32.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.24, including program basis document PBD-AMP-B.1.24, “One-Time Inspection,” Revision 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M32. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.24 and associated bases documents to determine their consistency with GALL AMP XI.M32.

During the audit, the project team noted that the applicant did not identify any exceptions to the GALL AMP XI.M32 in the LRA as described in program basis document PBD-AMP-B.1.24.

In addition, the project team also reviewed the OCGS document titled “Inspection Sample Basis; Oyster Creek License Renewal Project,” dated August 16, 2005. This document describes the process to be used in determining the inspection sample population and location for the OCGS One-Time Inspection Program.

In reviewing this AMP, the project team noted that Table 3.3.1, item 43, in the OCGS LRA stated that the One-Time Inspection Program will be used to verify the effectiveness of the Selective Leaching of Materials Program; however, this intended use is not discussed in the program description. The applicant was asked to clarify this intended use of the One-Time Inspection Program.

The applicant stated that the one-time inspection aging management program does not verify the effectiveness of the selective leaching of materials aging management program. As described in AMP B.1.25, the selective leaching of materials aging management program is itself a one-time inspection to confirm that loss of material due to the selective leaching aging mechanism is not occurring.

In its letter dated April 17, 2006 (ML061150320), the applicant committed to correct line item 43 in Table 3.3.1 to delete reference to using the one-time inspection to verify the effectiveness of the Selective Leaching of Materials Program. **This is Audit Commitment 3.0.3.1.4-1.**

The project team concurred with the applicant's commitment to revise line item 43 in Table 3.3.1 of the OCGS LRA to delete reference to using the one-time inspection to verify the effectiveness of the Selective Leaching of Materials Program since this not one of the intended uses of the One-Time Inspection Program.

The project team also noted in the OCGS LRA program description for AMP B.1.24 that this program is new and will include program elements to determine the sample population size and location, as well as inspection techniques. The applicant was asked to provide additional information on the rational to be used in selecting the population size and location, as well as the inspection techniques.

In its response, the applicant stated that an inspection sample basis document has been prepared for one-time inspections. This document provides information on component population, sample population, and expansion criteria for the various applications of the One-Time Inspection Program. Implementation of the one-time inspections will be through the normal maintenance planning process.

The project team reviewed the inspection sample basis document, which is an OCGS report titled "Inspection Sample Basis, Oyster Creek License Renewal Project," dated August 16, 2005, and noted that it did not include a document identification number or approval signatures, indicating that it was not a controlled document. The applicant was asked to provide the administrative controls that would be used to control this document to ensure that the sample selection process remains consistent with the recommendations in the GALL Report.

The applicant stated that the inspection sample basis document will be converted to a controlled project position paper, which will be referenced in the program basis document, AMP-PBD-B.1.24. The project team determined that converting this document to a position paper would provide the necessary administrative oversight to ensure that the document is properly controlled.

The project team also noted that the OCGS inspection sample basis document for AMP B.1.24 stated that the one-time inspection sample size for stress corrosion cracking will include only one stainless steel pipe section in a stagnant or low flow area > 140ºF. The applicant was asked to provide the rational and justification for selecting the number of samples for each aging effect. In particular, the applicant was asked to discuss why one sample of stainless steel piping was considered to be an adequate population for detecting stress corrosion cracking.

The applicant also stated that the selected sample for one-time inspections for stress corrosion cracking will be revised in the sample basis document for AMP B.1.24 as follows and the implementation is being tracked within the Amergen tracking process, to be completed, as necessary, prior to the period of extended operation:

1. Two (2) stainless steel pipe sections in a stagnant or low flow area (>140ºF) in the reactor water cleanup system will be inspected. The one-time inspection for cracking will be by ultrasonic testing (UT). An example of an acceptable sample

location includes the cleanup auxiliary pump discharge line between V-16-13 and the 6" RWCU main process line.

2. Two (2) stainless steel pipe sections in a stagnant or low flow area (>140ºF) in the isolation condenser system will be inspected. The one-time inspection for cracking will be by UT. Examples of acceptable sample locations include the 12" or 16" non-class 1 isolation condenser steam inlet piping. Portions of the 8" or 10" condensate return lines up to the normally closed isolation condenser condensate return valves can also be inspected, if they are >140ºF.

The applicant further stated that the one-time inspections performed for the non-class 1 portions of the isolation condenser system to verify the effectiveness of the water chemistry program to manage cracking are different inspections from those inspections performed in conjunction with ASME Section XI, water chemistry, and the BWR stress corrosion cracking AMPs for RCPB piping, piping components, and piping elements. The one-time inspections specified for the non-RCPB portions of the reactor water cleanup system are inspections beyond those required by the BWR reactor water cleanup system aging management program.

The project team reviewed the applicant's response and determined that the revised inspection sample population, which will now consist of two (2) stainless steel pipe sections in a stagnant or low flow area (>140ºF), will provide multiple data points for determining whether stress corrosion cracking is occurring. This will minimize the chance of obtaining an unrepresentative result for the system being inspected; therefore, the project team found it to be acceptable.

The project team reviewed those portions of the applicant's One-Time Inspection Program for which the applicant claims consistency with GALL AMP XI.M32 and found that they are consistent with the GALL Report AMP. The description of OCGS AMP B.1.24 in the OCGS LRA does not state any exceptions to AMP XI.M32 in the GALL Report. However, in their reconciliation document, the applicant identified the following exceptions to the GALL Report program. The project team found that the applicant's One-Time Inspection Program conforms to the recommended GALL AMP XI.M32, with the exceptions described below.

3.0.3.1.4.3 Exceptions to the GALL Report

Exception 1

Elements: Program Description

1. Scope of Program
2. Preventive Actions
3. Parameters Monitored or Inspected
4. Detection of Aging Effects
5. Monitoring and Trending
6. Acceptance Criteria

Exception: NUREG-1801 states in XI.M32 that one-time inspection of Class 1 piping less than or equal to NPS 4 is addressed in Chapter XI.M35. NUREG-1801 aging management program XI.M35, will not be used at Oyster Creek. The new Oyster Creek One-Time Inspection aging management program will include the one-time inspection of Class 1 piping less than or equal to NPS 4. *This is a new exception based on the* *reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL.*

The GALL Report identifies the following recommendations for the “program description,” “scope of program,” “preventive actions,” “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” and “acceptance criteria” program elements associated with the exception taken:

Program Description: The program includes measures to verify the effectiveness of an aging management program (AMP) and confirm the insignificance of an aging effect. Situations in which additional confirmation is appropriate include (a) an aging effect is not expected to occur but the data is insufficient to rule it out with reasonable confidence; (b) an aging effect is expected to progress very slowly in the specified environment, but the local environment may be more adverse than that generally expected; or (c) the characteristics of the aging effect include a long incubation period. For these cases, there is to be confirmation that either the aging effect is indeed not occurring, or the aging effect is occurring very slowly so as not to affect the component or structure intended function during the period of extended operation.

A one-time inspection may also be used to provide additional assurance that aging that has not yet manifested itself is not occurring, or that the evidence of aging shows that the aging is so insignificant that an aging management program is not warranted. (Class 1 piping less than or equal to NPS 4 is addressed in Chapter XI.M35.

1. *Scope of Program*: The program includes measures to verify that unacceptable degradation is not occurring, thereby validating the effectiveness of existing AMPs or confirming that there is no need to manage aging-related degradation for the period of extended operation. The structures and components for which one-time inspection is specified to verify the effectiveness of the AMPs (e.g., water chemistry control, etc.) have been identified in the GALL Report. Examples include the feedwater system components in boiling water reactors (BWRs) and pressurized water reactors (PWRs).

2. *Preventive Actions*: One-time inspection is an inspection activity independent of methods to mitigate or prevent degradation.

3. *Parameters Monitored or Inspected*: The program monitors parameters directly related to the degradation of a component. Inspection is to be performed by qualified personnel following procedures consistent with the requirements of the American Society of Mechanical Engineers (ASME) Code and 10 CFR Part 50, Appendix B, using a variety of nondestructive examination (NDE) methods, including visual, volumetric, and surface techniques.

4. *Detection of Aging Effects*: The inspection includes a representative sample of the system population, and, where practical, focuses on the bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin. The program will rely on established NDE techniques, including visual, ultrasonic, and surface techniques that are performed by qualified personnel following procedures consistent with the ASME Code and 10 CFR Part 50, Appendix B. The inspection and test techniques will have a demonstrated history of effectiveness in detecting the aging effect of concern.

5. *Monitoring and Trending*: The program provides for increasing of the inspection sample size and locations in the event that aging effects are detected. Determination of the sample size is based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience. Unacceptable inspection findings are evaluated in accordance with the site corrective action process to determine the need for subsequent (including periodic) inspections and for monitoring and trending the results.

6. *Acceptance Criteria*: Any indication or relevant conditions of degradation detected are evaluated. For example, the ultrasonic thickness measurements are to be compared to predetermined limits, such as the design minimum wall thickness for piping.

The applicant was asked to confirm that AMP B.1.24 in the OCGS LRA will be revised to include this exception.

In its letter dated March 30, 2006 (ML060950408), the applicant committed to revise AMP B.1.24 in the OCGS LRA to include the exception identified in the reconciliation document, which states that the new Oyster Creek one-time inspection aging management program will include the one-time inspection of Class 1 piping less than or equal to NPS 4, and GALL AMP XI.M35 will not be used. This is **Audit Commitment 3.0.3.1.4-2.**

In reviewing this exception, the project team compared the program elements for OCGS AMP B.1.24 to those for AMP XI.M35 in the GALL Report to determine if they were consistent for the inspection of piping less than 4-inch NPS. Specifically, since the selection of the one-time inspection sample population for OCGS AMP B.1.24 is described in the OCGS inspection sample basis document, which is an OCGS report titled “Inspection Sample Basis, Oyster Creek License Renewal Project,” dated August 16, 2005, the project team reviewed this document to determine how the small bore piping inspection sample population will be determined. The aging management program in the GALL Report, AMP XI.M35, recommends that, for ASME Code Class 1 small bore piping, a one-time inspection using volumetric examination be performed on selected weld locations to detect cracking. The sample size should be based on susceptibility, inspectability, dose considerations, operating experience, and limiting locations of the total population of ASME Code Class 1 smallbore piping locations.

The project team noted that the OCGS inspection sample basis document stated that sample size for Class 1 piping less than 4 inch nominal pipe size (NPS) will include 10% of the total butt welds, and inspection locations will be based on physical accessibility, exposure levels, non-destructive examination (NDE) techniques, etc., and will be determined by the site. The applicant was asked to clarify the process for selecting pipe inspection samples to ensure that different piping sizes are included in the sample selection for Class 1 piping less than 4 inches NPS.

In its response, the applicant stated that, based on the Oyster Creek line list for reactor coolant pressure boundary systems, fittings less than 2.5 inches are socket weld ends. Fittings greater than or equal to 2.5 inches are butt weld ends. The sample population for one-time inspection of Class 1 piping less than NPS 4 will, therefore, consist primarily of samples greater than or equal 2.5 inches and less than 4 inches.

The project team reviewed the applicant’s response and determined that the inspection sample population would be limited to piping greater than 2.5 inches; therefore, it would include only butt welded piping. The project team found the applicant’s approach for selecting the inspection sample population unacceptable since it did not address how aging of non-butt welded piping less than NPS 4 would be managed. The applicant was asked to provide additional information on how the sample selection process will ensure that samples of all different pipe sizes less than NPS 4 are inspected. Specifically, the applicant was asked if there are any Class 1 pipes less than NPS 4 in the scope of this AMP that are not butt welded (e.g., socket welded), and how these non-butt welded pipes would be inspected. The project team also asked the applicant to provide information on Oyster Creek's operating experience with Class 1 piping less than NPS 4.

In its response, the applicant stated the following:

> a) The one-time inspection for Class 1 piping, piping components, and piping elements for cracking initiation and growth due to thermal and mechanical loading, stress corrosion cracking, and intergranular stress corrosion cracking includes a representative sample of the susceptible items, and, where practical, focuses on the bounding or lead items most susceptible to cracking due to time in service, severity of operating conditions, or lowest design margin. Applying ASME Code Case N-578-1, "Risk Informed Requirements for Class 1, 2, or 3 Piping, Method B Section XI, Division 1" is one method other applicants have used for determining sample size for one-time inspections. With this method, butt welds are evaluated based on risk and "binned" into high, medium, and low risk categories. The selected sample for one-time inspection volumetric examination then included 10% of the high and medium risk butt welds. Oyster Creek; however, has not employed risk informed ISI and does not currently have a risk based evaluation that categorizes the Class 1 butt welds into risk categories. This evaluation is extensive and to perform this evaluation at this time is not practical, so ASME Code Case N-578-1 will not be utilized. Instead, the one-time inspection sample size will include 10% of the total butt welds in Class 1 piping less than NPS 4. The actual inspection locations will be based on physical accessibility, exposure levels, NDE techniques, etc. and will be determined with site involvement. UT techniques consistent with the ASME Code and 10 CFR Part 50, Appendix B that permit the inspection of the inside surfaces of the item will be used for the inspection of butt welds.
>
> The applicant further stated that Oyster Creek piping is based upon the ANSI B31.1 (1963) Power Piping specification. The Class 1 piping classification is based upon ASME Section XI. The Oyster Creek line specifications, piping and instrument drawings, isometric configuration drawings and input from the Oyster Creek ISI coordinator were used to determine the location and population of butt welds less than or equal to four inches. The population includes welds on the reactor recirculation system, the CRD return line, the reactor vessel bottom head drain line, the reactor head vent line (main steam system), and the reactor water cleanup system. The butt welds less than NPS 4 in these systems are two and three inch in size (there is no 2½ inch Class 1 piping; nor are there any butt welds on the 1 inch Class 1 piping). The proposed sample includes a representative sample of welds from these systems and includes both two and three inch NPS pipe.
>
> b) The majority of Class 1 piping less than NPS 4 is socket welded. The ASME Section XI Class 1 piping program requires surface examination of socket welded connections. The One-Time Inspection Program originally did not include in-situ volumetric or destructive examination of socket welded connections. The One-Time Inspection Program was to include opportunistic examinations of Class 1 socket welded connections less than NPS 4. Socket weld failures will be evaluated in accordance with

the Oyster Creek 10 CFR Part 50, Appendix B corrective action program to determine failure mechanisms and corrective actions. In addition, the plant modification process will require that any class 1 socket welded connection less than NPS 4 that has been removed during the installation of a plant modification be examined for cracking and cracking mechanisms.

c) Based on a review of the Oyster Creek CAP System (Corrective Action Program) from 1998 through present, cracking due to SCC, IGSCC, or thermal and mechanical loading has not been found on class 1 piping less than NPS 4. An evaluation of Oyster Creek OE from 1985 through 2000 was performed in 2000 in response to industry concerns related to vibration related and thermal fatigue failures of small bore piping. That review identified one (1) event in which a safety-related small bore socket welded connection failed. This failure was attributed to a defective weld rather than vibration related or thermal fatigue.

Mechanical/Vibration Fatigue: Vibration induced socket weld failures is a material degradation issue that can result in crack initiation and growth. Small bore pipe and socket welded vent and drain connections in the immediate proximity of vibration sources tend to be most susceptible to high cycle mechanical fatigue. Vibration fatigue does not lend itself to periodic in-service examinations as a means of managing this aging mechanism. Vibration induced fatigue is fast acting and is typically detected early in a component's life. The nature of this mechanism is such that, generally, almost the entire fatigue life of the component is expended during the initial phase of crack initiation. Once a crack initiates, failure quickly follows. The period of time between crack initiation, i.e. a crack size that is detectable by volumetric examination, and the failure of the pressure boundary is very small and is usually measured in days to months and not years. An evaluation of Oyster Creek OE from 1985 through 2000 was performed in 2000 in response to industry concerns related to vibration related and thermal fatigue failures of small bore piping. That review identified one (1) event in which a safety-related small bore socket welded connection failed. This failure was attributed to a defective weld rather than vibration related or thermal fatigue. Based upon the Oyster Creek plant specific operating experience, and rationale provided above, cracking due to vibration-induced fatigue is not considered an aging effect for the period of extended operation.

Thermal Fatigue: A relatively small number of thermal related failures have occurred in small-bore piping (reference: Pacific Northwest National Laboratory report PNNL-13930, "Program Plan for Acquiring and Examining Naturally Aged Materials and Components for Nuclear Reactors," dated December 2001). Fatigue failures in safety-related systems and components have been rare and fatigue in pressure-retaining equipment is generally detected as small cracks or leaks, caught before reaching a size that could cause a pressure boundary rupture. Thus fatigue is not considered a safety issue (reference: TR-104534, "EPRI Fatigue Management Handbook," dated December 1994). Of those that have occurred, the more common source of thermal fatigue was either (1) cracking associated with the interaction of valve leakage and cyclic effects and (2) cyclic turbulent penetration effects of isolated small-bore piping or drain lines. An evaluation of Oyster Creek OE from 1985 through 2000 was performed in 2000 in response to industry concerns related to vibration related and thermal fatigue failures of small bore piping. That review identified one (1) event in which a safety-related small bore socket welded connection failed. This failure was attributed to a defective weld rather than vibration related or thermal fatigue. The issue of thermal fatigue is the subject of EPRI Report 1000701, "Interim Thermal Fatigue Management Guideline (MRP-24)," dated January 2001 which is referenced in GALL program XI.M35, in program Element 1 "Scope of Program." As discussed in PBD-B.1.24, EPRI Report 1000701 recommends specific locations for assessment and/or inspection where cracking and leakage has been identified in nominally stagnant non-isolable piping attached to reactor coolant systems in domestic and similar foreign PWRs. These inspection recommendations do not apply to Oyster Creek which is a BWR. However, Oyster Creek has evaluated the potential for cracking in nominally stagnant non-isolable piping attached to reactor coolant systems and it was concluded that there are no systems with unisolable sections that could be subjected to thermal stratification or oscillations. This evaluation is summarized as follows: IN 97-46 discusses a situation that occurred at Oconee Unit 2 where cracks developed in an unisolable section of a combined makeup (MU) and high-pressure injection (HPI) line. The IN goes on to reference NRC Bulletin 88-08 and its supplements. Bulletin 88-08 describes the circumstances that occurred at Farley 2 where a crack developed in an unisolable section of ECCS piping. The crack resulted from high cycle thermal fatigue caused by relatively cold water leaking through a closed globe valve. Oyster Creek performed a review of systems connected to the Reactor Coolant System in response to NRC Bulletin 88-08 and its Supplements to determine whether unisolable sections of piping connected to the Reactor Coolant System could be subjected to stresses from temperature stratification or temperature oscillations. It was concluded that there are no systems with unisolable sections which could be subjected to thermal stratification or oscillations. The piping system evaluations encompassed both the weldments (as required by Bulletin 88-08) and the base metal (as required by Supplement 1 to Bulletin 88-08).

Stress Corrosion Cracking: Three simultaneous conditions must be present for IGSCC to occur: susceptible material, environment, and tensile stress. Tensile stress at the weld root, which is exposed to impurities in the reactor coolant that can accelerate the initiation and propagation of IGSCC, is typically produced during butt welding of piping components and is less of a concern with socket welded connections. The Oyster Creek One-Time Inspection Program for class 1 piping less than NPS 4 will focus on full penetration butt welds which are more susceptible (bounding) than socket welded connections to the stress corrosion cracking aging mechanism.

In reviewing the applicant’s response, the project team recognized that failures in socket welded piping less than NPS 4 have been prevalent in the industry, and have received increasing attention by the staff. As noted in the applicant’s response, socket welded piping accounts for the majority of piping less than NPS 4; therefore, an acceptable method of ensuring that aging of these welds will be managed for the period of extended operation must be demonstrated. While the applicant’s program will inspect butt welded piping less than NPS 4, there is no evidence to demonstrate that this inspection sample population can be considered a leading indicator or a limiting location for failures in socket welded piping.

In its response, the applicant stated that the OCGS One-Time Inspection Program will include opportunistic examinations of Class 1 socket welded connections less than NPS 4. Socket weld failures will be evaluated in accordance with the Oyster Creek 10 CFR Part 50, Appendix B corrective action program to determine failure mechanisms and corrective actions. The project team recognized that opportunistic inspection of socket weld failures will provide insights into the cause of the failures; however, as noted in NRC Branch Technical Position RLSB-1 (SRP-LR, Appendix A), in order for an aging management program to be considered effective, detection of aging effects must occur before there is a loss of the component's intended function. Further, a program based solely on detecting component failure should not be considered an effective aging management program for license renewal.

In its response, the applicant further stated that the plant modification process will require that any class 1 socket welded connection less than NPS 4 that has been removed during the installation of a plant modification be examined for cracking and cracking mechanisms. The project team recognized that this would provide reasonable assurance that cracking of socket welded small bore piping is not occurring. However, the project team did not feel that there was certainty that a socket weld would be examined prior to entering the period of extended operation.

In response to the project team's questions on this issue, the applicant committed to the following: "The One-Time Inspection Program will also include destructive or non-destructive examination of one socket welded connection using techniques proven by past industry experience to be effective for the identification of cracking in small bore socket welds. This examination will be an examination of opportunity (e.g., socket weld failure or socket weld replacement). Should an inspection of opportunity not occur prior to entering the period of extended operation, a susceptible small bore socket weld will be examined either destructively or non-destructively prior to entering the period of extended operation. The current plan is to examine a susceptible small bore Class 1 elbow off of an isolation condenser system drain line. Results of the inspection will be evaluated in accordance with the Oyster Creek 10 CFR Part 50, Appendix B Corrective Action process."

In its letter dated May 1, 2006, (AmerGen Letter No. 2130-06-20328), the applicant committed to the following: The One-Time Inspection Program will also include destructive or non-destructive examination of one socket welded connection using techniques proven by past industry experience to be effective for the identification of cracking in small bore socket welds. Should an inspection opportunity not occur (e.g., socket weld failure or socket weld replacement), a susceptible small-bore socket weld will be examined either destructively or non-destructively prior to entering the period of extended operation. **This is Audit Commitment 3.0.3.1.4-3.** This specific commitment will be added to the LRA Appendix A.5 Commitment List, as part of Commitment 24 associated with One-Time Inspection Program.

The project team determined that the applicant has now committed to volumetrically or destructively examine at least one socket weld prior to the period of extended operation, and perform examination of 10% of the butt welded small bore piping, in response to the project team's concern in this area. As this is a sampling process, the project team determined that one socket weld will represent the population for Class 1 piping less than 4-inch NPS.

<u>Exception 2</u>

Elements: Program Description
1. Scope of Program
3. Parameters Monitored or Inspected
4. Detection of Aging Effects
5. Monitoring and Trending
6. Acceptance Criteria

Exception: NUREG-1801 references, in XI.M32 and XI.M35, the 2001 ASME Section XI B&PV Code, including the 2002 and 2003 Addenda for

Subsections IWB, IWC, and IWD. The current Oyster Creek ISI Program Plan for the fourth ten-year inspection interval effective from October 15, 2002 through October 14, 2012, approved per 10CFR50.55a, is based on the 1995 ASME Section XI B&PV Code, including 1996 addenda. The next 120-month inspection interval for Oyster Creek will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a twelve months before the start of the inspection interval. *This is a new exception based on the reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL.*

The GALL Report identifies the following recommendations for the “program description,” “scope of program,” “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” and “acceptance criteria” program elements associated with the exception taken:

Program Description: The program includes measures to verify the effectiveness of an AMP and confirm the insignificance of an aging effect. Situations in which additional confirmation is appropriate include (a) an aging effect is not expected to occur but the data is insufficient to rule it out with reasonable confidence; (b) an aging effect is expected to progress very slowly in the specified environment, but the local environment may be more adverse than that generally expected; or (c) the characteristics of the aging effect include a long incubation period. For these cases, there is to be confirmation that either the aging effect is indeed not occurring, or the aging effect is occurring very slowly so as not to affect the component or structure intended function during the period of extended operation.

A one-time inspection may also be used to provide additional assurance that aging that has not yet manifested itself is not occurring, or that the evidence of aging shows that the aging is so insignificant that an aging management program is not warranted. (Class 1 piping less than or equal to NPS 4 is addressed in Chapter XI.M35.)

1. *Scope of Program*: The program includes measures to verify that unacceptable degradation is not occurring, thereby validating the effectiveness of existing AMPs or confirming that there is no need to manage aging-related degradation for the period of extended operation. The structures and components for which one-time inspection is specified to verify the effectiveness of the AMPs (e.g., water chemistry control, etc.) have been identified in the GALL Report.

3. *Parameters Monitored or Inspected*: The program monitors parameters directly related to the degradation of a component. Inspection is to be performed by qualified personnel following procedures consistent with the requirements of the ASME Code and 10 CFR Part 50, Appendix B, using a variety of NDE methods, including visual, volumetric, and surface techniques.

4. *Detection of Aging Effects*: The inspection includes a representative sample of the system population, and, where practical, focuses on the bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin. The program will rely on established NDE techniques, including visual, ultrasonic, and surface techniques that are performed by qualified personnel

following procedures consistent with the ASME Code and 10 CFR Part 50, Appendix B. The inspection and test techniques will have a demonstrated history of effectiveness in detecting the aging effect of concern.

5. Monitoring and Trending: The program provides for increasing of the inspection sample size and locations in the event that aging effects are detected. Determination of the sample size is based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience. Unacceptable inspection findings are evaluated in accordance with the site corrective action process to determine the need for subsequent (including periodic) inspections and for monitoring and trending the results.

6. *Acceptance Criteria*: Any indication or relevant conditions of degradation detected are evaluated. For example, the ultrasonic thickness measurements are to be compared to predetermined limits, such as the design minimum wall thickness for piping.

The applicant was asked to confirm that AMP B.1.24 in the OCGS LRA will be revised to include this exception.

In its letter dated March 30, 2006 (ML060950408), the applicant committed to revise AMP B.1.24 in the OCGS LRA to include the exception identified in the reconciliation document, which states that the 1995 ASME Section XI B&PV Code, including 1996 addenda, is currently used at Oyster Creek. **This is Audit Commitment 3.0.3.1.4-4.**

The project team evaluated this exception as part of its review of OCGS AMP B.1.1 and found it acceptable. The project teams's evaluation is discussed in Section 3.0.3.2.1.3 of this audit and review report.

<u>Exception 3</u>

Elements:	Program Description 1. Scope of Program 5. Monitoring and Trending
Exception:	NUREG-1801 states in XI.M35 that the guidelines of EPRI Report 1000701, "Interim Thermal Fatigue Management Guideline (MRP-24)," January 2001 should be used for identifying piping susceptible to potential effects of thermal fatigue. EPRI Report 1000701 recommends specific locations for assessment and/or inspection where cracking and leakage has been identified in nominally stagnant non-isolable piping attached to reactor coolant systems in domestic and similar foreign PWRs. As Oyster Creek is a BWR, these inspection guidelines are not applicable. *This is a new exception based on the reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL*.

The GALL Report identifies the following recommendations for the “program description,” “scope of program,” and “monitoring and trending” program elements associated with the exception taken:

Program Description: The program includes measures to verify the effectiveness of an AMP and confirm the insignificance of an aging effect. Situations in which additional confirmation is appropriate include (a) an aging effect is not expected to occur but the data is insufficient to rule it out with reasonable confidence; (b) an aging effect is expected to progress very slowly in the specified environment, but the local environment may be more adverse than that generally expected; or (c) the characteristics of the aging effect include a long incubation period. For these cases, there is to be confirmation that either the aging effect is indeed not occurring, or the aging effect is occurring very slowly so as not to affect the component or structure intended function during the period of extended operation.

A one-time inspection may also be used to provide additional assurance that aging that has not yet manifested itself is not occurring, or that the evidence of aging shows that the aging is so insignificant that an aging management program is not warranted. (Class 1 piping less than or equal to NPS 4 is addressed in Chapter XI.M35.)

1. *Scope of Program*: The program includes measures to verify that unacceptable degradation is not occurring, thereby validating the effectiveness of existing AMPs or confirming that there is no need to manage aging-related degradation for the period of extended operation. The structures and components for which one-time inspection is specified to verify the effectiveness of the AMPs (e.g., water chemistry control, etc.) have been identified in the GALL Report.

5. *Monitoring and Trending*: The program provides for increasing of the inspection sample size and locations in the event that aging effects are detected. Determination of the sample size is based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience. Unacceptable inspection findings are evaluated in accordance with the site corrective action process to determine the need for subsequent (including periodic) inspections and for monitoring and trending the results.

The applicant was asked to confirm that AMP B.1.24 in the OCGS LRA will be revised to include this exception.

In its letter dated March 30, 2006 (ML060950408), the applicant committed to revise AMP B.1.24 in the OCGS LRA to include the exception identified in the reconciliation document, which states that EPRI Report 1000701 is not applicable at Oyster Creek. **This is Audit Commitment 3.0.3.1.4-5.**

In reviewing this exception, the project team noted that, while EPRI Report 1000701 focuses on locations susceptible to thermal fatigue that are specific to PWR plants, it also includes generic guidance that may be useful for BWR plants. The applicant was asked to clarify whether the generic guidance in EPRI Report 1000701 was considered in the development of OCGS AMP B.1.24.

In its response, the applicant stated that the Oyster Creek evaluation to identify piping potentially susceptible to the effects of thermal fatigue is provided in program basis document PBD-AMP-B.1.24, Section 3.1. This evaluation addresses the generic guidance of the EPRI document for identification of locations. No locations were identified as requiring inspection. The project team reviewed Section 3.1 of the program basis document for OCGS AMP B.1.24 and confirmed that the evaluation used the generic guidance in the EPRI report. The evaluation identified no locations at Oyster Creek that would be subject to thermal fatigue. On this basis, the project team determined that this exception is acceptable.

3.0.3.1.4.4 Enhancements

None

3.0.3.1.4.5 Operating Experience

In the OCGS LRA, the applicant stated that this program applies to potential aging effects for which there are currently no operating experience indicating the need for an aging management program. Nevertheless, the elements that comprise these inspections (e.g., the scope of the inspections and inspection techniques) are consistent with industry practice.

Since this is a new program, there was no plant-specific operating experience for the project team to review. However, the project team expects that OCGS AMP B.1.24 will adequately manage the aging effects for which it is credited on the basis that it is consistent with GALL AMP XI.M32, with exceptions.

The project team recognized that the corrective action program, which captures internal and external plant operating experience issues, will ensure that operating experience is reviewed and incorporated in the future to provide objective evidence to support the conclusion that the effects of aging are adequately managed.

3.0.3.1.4.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the One-Time Inspection Program in OCGS LRA, Appendix A, Section A.1.24, which states that the Oyster Creek one-time inspection aging management program is a new program that will address potentially long incubation periods for certain aging effects and will provide a means of confirming that an aging effect is either not occurring or is progressing so slowly as to not have an effect on the intended function of a structure or component within the extended period of operation. The One-Time Inspection Program will provide measures to verify that an aging management program is not needed, confirms the effectiveness of existing activities, or determines that degradation is occurring which will require evaluation and corrective action. The inspections will be implemented prior to the period of extended operation to manage the effects of aging for selected components within the scope of license renewal.

Inspection methods will include visual examination or volumetric examinations. Acceptance criteria are in accordance with industry guidelines, codes, and standards. The One-Time Inspection Program provides for the evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could jeopardize an intended function before the end of the period of extended operation. Should aging effects be detected, the program triggers actions to characterize the nature and extent of the aging effect and determines what subsequent monitoring is needed to ensure intended functions are maintained during the period of extended operation.

The project team also reviewed the applicant's license renewal commitment list in Appendix A of the OCGS LRA, and confirmed that this program is identified as a new program that will be implemented prior to the period of extended operation as item 24 of the commitments. The specific commitments identified in this report section will be added to the LRA Appendix A.5 Commitment List, as part of Commitment 24 associated with the One-Time Inspection Program. In its letter dated March 30, 2006 (ML060950408), the applicant committed to make the following revisions to the OCGS LRA:

- AMP B.1.24 in the OCGS LRA will be revised to include the exception identified in the reconciliation document, which states that the new Oyster Creek one-time inspection aging management program will include the one-time inspection of Class 1 piping less than or equal to NPS 4. (Commitment 3.0.3.1.4-2)

- AMP B.1.24 in the OCGS LRA will be revised to include the exception identified in the reconciliation document, which states that the 1995 ASME Section XI B&PV Code, including 1996 addenda, is currently used at Oyster Creek. (Commitment 3.0.3.1.4-4)

- AMP B.1.24 in the OCGS LRA will be revised to include the exception identified in the reconciliation document, which states that EPRI Report 1000701 is not applicable at Oyster Creek. (Commitment 3.0.3.1.4-5)

In its letter dated April 17, 2006 (ML061150320), the applicant committed to make the following revision to the OCGS LRA:

- AMR line item 43 in Table 3.3.1 will be revised to delete reference to using the one-time inspection to verify the effectiveness of the Selective Leaching of Materials Program since this is not one of the intended uses of the one-time inspection. (Commitment 3.0.3.1.4-1)

In its letter dated May 1, 2006 (AmerGen Letter No. 2130-06-20328), the applicant committed to make the following revision to the OCGS LRA:

    - AMP B.1.24 in the OCGS LRA will be revised to include destructive or non-destructive examination of one socket welded connection. (Audit Commitment 3.0.3.1.4-3)

The applicant’s license renewal commitment list and UFSAR update are to be revised to reflect these new commitments.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.24. Contingent upon the inclusion of commitments 3.0.3.1.4-1 thru 5, the project team found that it was consistent with the GALL Report, and determined that it provided an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.1.4.7 <u>Conclusion</u>

On the basis of its audit and review of the applicant’s program, the project team found that those program elements for which the applicant claims consistency with the GALL Report are consistent with the GALL Report. In addition, the project team has reviewed the exceptions and the associated justifications and determined that the AMP, with exceptions, is adequate to manage the aging effects for which it is credited. The project team also reviewed the UFSAR Supplement for this AMP and, contingent upon the inclusion of Audit Commitments 3.0.3.1.4-1 thru 5, found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.5 Selective Leaching of Materials (OCGS AMP B.1.25)

In OCGS LRA, Appendix B, Section B.1.25, the applicant stated that OCGS AMP B.1.25, "Selective Leaching of Materials," is a new plant program that is consistent with GALL AMP XI.M33, "Selective Leaching of Materials."

3.0.3.1.5.1 Program Description

The applicant stated, in the OCGS LRA, that this program will consist of one-time inspections to determine if loss of material due to selective leaching is occurring. The scope of the program includes susceptible components such as piping, pumps and valves within the scope of license renewal that are exposed to raw water, closed cooling water, treated water, auxiliary steam, condensation or soil. Susceptible component materials are gray cast iron, brass and bronze with greater than 15% zinc, and aluminum bronze with greater than 8% aluminum.

The applicant also stated that the One-Time Inspection Program includes visual inspections consistent with ASME Section XI VT-1 requirements, hardness tests and other appropriate examination methods as may be required to confirm or rule out selective leaching, and to evaluate the remaining component wall thickness. Components of the susceptible materials are selected from the different potentially aggressive environments. The purpose of the program is to determine if loss of material due to selective leaching is occurring. If selective leaching is found, the program provides for evaluation as to the effect it will have on the ability of the affected components to perform their intended function for the period of extended operation, and the need to expand the sample of components to be tested.

The applicant further stated that the program will be implemented prior to the period of extended operation.

3.0.3.1.5 2 Consistency with the GALL Report

In OCGS LRA, the applicant stated that OCGS AMP B.1.25 is consistent with GALL AMP XI.M33.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.25, including program basis document PBD-AMP B.1.25, “Selective Leaching of Materials,” Revision 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M33. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.25 and associated bases documents to determine consistency with GALL AMP XI.M33.

The project team reviewed those portions of the applicant’s Selective Leaching of Materials Program for which the applicant claims consistency with GALL AMP XI.M33 and found that they are consistent with this GALL Report AMP. The project team found that the applicant’s Selective Leaching of Materials Program conforms to the recommended GALL AMP XI.M33.

3.0.3.1.5 3 Exceptions to the GALL Report

None

3.0.3.1.5 4 Enhancements

None

3.0.3.1.5.5 Operating Experience

The applicant stated, in the OCGS LRA and the program basis document, that the Selective Leaching of Materials aging management program is new. Therefore, no programmatic operating experience is available.

The applicant stated that operating experience, both internal and external, is used in two ways at Oyster Creek to enhance plant programs, prevent repeat events, and prevent events that have occurred at other plants from occurring at Oyster Creek. The first way in which operating experience is used is through the Oyster Creek operating experience process. The operating experience process screens, evaluates, and acts on operating experience documents and information to prevent or mitigate the consequences of similar events. The second way is through the process for managing programs. This process requires the review of program related operating experience by the program owner.

Demonstration that the Oyster Creek Selective Leaching of Materials aging management program to effectively manage loss of material in components susceptible to selective leaching will be achieved through objective evidence. The following industry operating experience and site-specific findings at Oyster Creek have been utilized in creating the Oyster Creek Selective Leaching of Materials aging management program:

> Industry operating experience has identified graphitization of submerged pump components from long-term immersion in saltwater environments and dezincification of copper alloy components. Graphitization has occurred in the Oyster Creek service water system and the circulating water system at the intake structure. In the case of the non-nuclear service water pumps, the pump suction bowls were at one time all made of cast iron. Submergence in the intake bay for years at a time caused severe graphitization of these bowls. This diagnosis was made at the time by a materials engineer on the staff of the pump company and was confirmed based on visual observation by the materials engineer of the previous plant owner.
>
> At this time, cast iron is no longer used or specified for use in the submerged portions of the service water pumps. Replacement parts are constructed from corrosion resistant materials. Additionally, the Emergency service water pumps do not contain cast iron parts.
>
> In the case of the circulating water pumps, the suction column sections (4) for each of the four pumps were all originally purchased with cast iron parts. Again, evidence of graphitic corrosion was found occurring early in their life. Steps were taken to replace the sections with new sections fabricated of stainless steel or carbon steel as deemed necessary. In addition, to prevent galvanic corrosion, insulation kits were installed between flanges where dissimilar metals met. At the present time, there remain a few sections still made of the original cast iron, but these are heavily coated. These

sections are visually inspected by the repair facility during overhauls in which the pump is removed from service and shipped to them. The circulating water pumps are not within the scope of License Renewal.

As such, sample inspections at Oyster Creek will include remaining cast iron components subjected to a saltwater environment.

Once implemented the Oyster Creek Selective Leaching of Materials aging management program will manage loss of material such that intended function(s) of components susceptible to selective leaching will be maintained consistent with the CLB for the period of extended operation.

The staff believes that the corrective action process will capture internal and external plant operating issues to ensure that aging effects are adequately managed.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant's selective leaching program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.1.5.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the Selective Leaching of Materials Program in OCGS LRA, Appendix A, Section A.1.25, which stated that the Selective Leaching of Materials aging management program is a new program that will consist of inspections of a representative selection of components of the different susceptible materials to determine if loss of material due to selective leaching is occurring. One-time inspections will be consistent with ASME Section XI VT-1 visual inspection requirements and supplemented by hardness tests and other examinations of the selected set of components. If selective leaching is found, the condition will be evaluated to determine the need to expand inspections. This new inspection program will be implemented prior to the period of extended operation.

The project team also reviewed the applicant's license renewal commitment list in Appendix A of the OCGS LRA, and confirmed that this program is identified as a new program that will be implemented prior to the period of extended operation as item 25 of the commitments.

The project team reviewed the UFSAR Supplement OCGS AMP B.1.25, found that it was consistent with the GALL Report, and determined that it provided an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.1.5.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that all the program elements are consistent with the GALL Report. On the basis of its review of the UFSAR Supplement for this program, the project team found that it provided an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.6 10 CFR Part 50, Appendix J (OCGS AMP B.1.29)

In OCGS LRA, Appendix B, Section B.1.29, the applicant stated that OCGS AMP B.1.29, ?10 CFR Part 50, Appendix J," is an existing plant program that is consistent with GALL AMP XI.S4, "10 CFR Part 50, Appendix J."

3.0.3.1.6.1 Program Description

The applicant stated, in the OCGS LRA, that this program provides for detection of age-related pressure boundary degradation and loss of leak tightness due to aging effects such as loss of material, cracking, or loss of preload in the primary containment and various systems penetrating primary containment. The program also detects age related degradation in material properties of gaskets, o-rings, and packing materials for the primary containment pressure boundary access points.

The applicant also stated that the program consists of tests performed in accordance with the regulations and guidance provided in 10 CFR Part 50 Appendix J, ?Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," Option B, Regulatory Guide 1.163, ?Performance-Based Containment Leak-Testing Program," NEI 94-01, ?Industry Guideline for Implementing Performance-Based Options of 10 CFR Part 50, Appendix J," ANSI/ANS 56.8, ?Containment System Leakage Testing Requirements," and station procedures. Containment leak rate tests are performed to assure that leakage through the primary containment and systems and components penetrating primary containment does not exceed allowable leakage limits specified in the Technical Specifications. An integrated leak rate test (ILRT) is performed during a period of reactor shutdown at the frequency specified in 10 CFR Part 50, Appendix J, Option B. Local leak rate tests (LLRT) are performed on isolation valves and containment access penetrations at frequencies that comply with the requirements of 10 CFR Part 50 Appendix J, Option B.

3.0.3.1.6.2 Consistency with the GALL Report

In OCGS LRA, the applicant stated that OCGS AMP B.1.29 is consistent with GALL AMP XI.S4.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.29, including program basis document, PBD-AMP-B.1.29, ?10 CFR Part 50, Appendix J," Rev. 0, 12/01/2005, which provides an assessment of the AMP elements' consistency with GALL AMP XI.S4. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.29 and associated bases documents to determine consistency with GALL AMP XI.S4.

The project team reviewed those portions of the applicant's 10 CFR Part 50, Appendix J program for which the applicant claims consistency with GALL AMP XI.S4 and found that they are consistent with this GALL Report AMP. The project team found that the applicant's 10 CFR Part 50, Appendix J program conforms to the recommended GALL AMP XI.S4.

3.0.3.1.6.3 Exceptions to the GALL Report

None

3.0.3.1.6.4 Enhancements

None

3.0.3.1.6.5 Operating Experience

The applicant stated, in the OCGS LRA and the program basis document, that the primary containment leakage testing program activities have been effective in maintaining the pressure integrity of the containment boundaries, including identification of leakage within the various systems pressure boundaries. The Oyster Creek facility demonstrates a good operating experience in maintaining the integrity of the containment boundaries as evidenced by the selection of Option B of 10 CFR Part 50 Appendix J leakage testing requirements. Oyster Creek has experienced 'as found' LLRT results that were in excess of the administrative limits for the individual containment penetration. Evaluations were performed and corrective actions were taken to restore the individual containment penetration leakage rates to within the established administrative leakage limits. The experience at Oyster Creek with the 10 CFR Part 50 Appendix J aging management program shows that the program is effective in managing loss of material, loss of preload, loss of sealing, loss of leak tightness, and cracking in the containment, associated welds, penetrations, and other access openings.

The applicant's operating experience review process includes both external and internal sources. External operating experience may include such things as INPO documents (e.g., SOERs, SERs, SENs, etc.), NRC documents (e.g., GLs, LERs, INs, etc.), General Electric documents (e.g., RCSILs, SILs, TILs, etc.), and other documents (e.g., 10CFR Part 21 Reports, NERs, etc.). Internal operating experience may include such things as event investigations, trending reports, and lessons learned from in-house events as captured in program notebooks, self-assessments, and in the 10 CFR Part 50, Appendix B corrective action process.

The applicant identified the following examples of operating experience to provide objective evidence that the Appendix J LRT program is effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

> The LLRT of V-26-8 determined that the leakage rate was above the alert limit for that valve. The rate was evaluated to be acceptable as-found. The valve was subsequently rebuilt and retested satisfactorily the next refueling outage. This example provides objective evidence that leak rates above administrative limits are identified for engineering evaluation, and that corrective actions are taken prior to component loss of intended function. This issue was identified in the applicant's CAP 02000-1355.
>
> The LLRT of V-19-20 determined that the leakage rate exceeded the action limit. The valve was repaired and the post-maintenance test LLRT was acceptable. This example provides objective evidence that components determined to exceed the allowable leakrates are entered into the corrective actions process, identified for repair, and subsequently retested in accordance with the program. This issue was identified in the applicant's CAP 02002-1564.
>
> The LLRT of MSIV NS04A determined that the leakage rate failed to meet acceptance criteria. The main seating surface was lapped and a successful LLRT was performed. As a result of this occurrence, the MSIV overhaul procedure was revised to include a documented management review prior to eliminating seat lapping after poppet replacement even if a successful blue check has been obtained. This example provides

objective evidence that a component exceeding the allowable leak rate was entered into the corrective actions process, repaired, and subsequently retested per the program. This issue was identified in the applicant's CAP 02004-3442.

Oyster Creek CAP O2005-1350 describes two issues regarding 10 CFR Part 50 Appendix J testing of components: 1.) Feed water piping expansion bellows (considered to be untestable) are not local leak rated tested. The bellows are pressurized during Integrated Leakage Rate Testing. Two main steam bellows and these two feed water bellows were the subject of a relief request from local leak rate testing due to their design. The main steam bellows were specifically identified in the exemption; the feed water bellows were not. Clarification of the feed water bellows exemption status is currently in process. 2.) Shutdown Cooling isolation valves are not leak rate tested due to a system configuration that lacks inboard test boundary valves. Although a previous NRC conclusion determined that these valves did not require an exemption, an error existed in the original exemption submittal. Documentation is not available to indicate these valves have ever been leak rate tested. Clarification of this issue status is in process. These examples provide objective evidence that deficiencies in the Appendix J program are entered into the corrective action process.

The applicant concluded that the operating experience of the Appendix J LRT program did not show any adverse trends in performance. Problems identified would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. There is sufficient confidence that the implementation of the LRT program will effectively maintain the integrity of containment, penetrations, and other access openings. Periodic self-assessments of the LRT program are performed to identify the areas that need improvement to maintain the quality performance of the program.

The project team reviewed the operating experience provided in the OCGS LRA and program basis document, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant's 10 CFR Part 50, Appendix J program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.1.6.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the 10 CFR Part 50, Appendix J program in OCGS LRA, Appendix A, Section A.1.29, which states that the 10 CFR Part 50, Appendix J program detects degradation of the containment structure and components that comprise the containment pressure boundary, including seals and gaskets. Containment leak rate tests are performed to assure that leakage through the primary containment and systems and components penetrating primary containment does not exceed allowable leakage limits specified in the technical specifications. This program complies with Option B requirements of 10 CFR Part 50 Appendix J with plant-specific exceptions approved by the NRC as part of license amendments, and implements the guidelines provided in RG 1.163 and NEI 94-01.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.29, found that it was consistent with the GALL Report, and determined that it provided an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.1.6.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that all the program elements are consistent with the GALL Report. On the basis of its review of the UFSAR Supplement for this program, the project team found that it provided an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.7 Masonry Wall Program (OCGS AMP B.1.30)

In OCGS LRA, Appendix B, Section B.1.30, the applicant stated that OCGS AMP B.1.30, "Masonry Wall Program," is an existing plant program that is consistent with GALL AMP XI.S5, "Masonry Wall Program." The applicant stated that the Masonry Wall Program is implemented through its structures monitoring program (OCGS AMP B.1.31).

Because the applicant implements its Masonry Wall Program through its structures monitoring program, the project team also confirmed that the scope of the structures monitoring program, which is evaluated in Section 3.0.4.2.24 of this audit and review report, includes the elements of the Masonry Wall Program.

3.0.3.1.7.1 Program Description

The applicant stated, in the OCGS LRA, that this program is part of its Structures Monitoring Program (OCGS AMP B.1.31). The program is based on the guidance provided in Bulletin 80-11, ?Masonry Wall Design," and IN 87-67, ?Lessons Learned from Regional Inspections of Licensee Actions in Response to Bulletin 80-11," and is implemented through station procedures. The scope of program includes all masonry walls that perform an intended function in accordance with 10 CFR 54.4. The program requires inspection of masonry walls for cracking on a frequency of 4 years, so that the established evaluation basis for each masonry wall remains valid during the period of extended operation.

3.0.3.1.7.2 Consistency with the GALL Report

In OCGS LRA, the applicant stated that OCGS AMP B.1.30 is consistent with GALL AMP XI.S5.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.30, including PBD-AMP-B.1.30, "Masonry Wall Program," Revision 0,12/18/05, which provides an assessment of the AMP elements' consistency with GALL AMP XI.S5. For additional information, see Section 3.0.3.2.24.2 of this audit and review report. The project team found that the applicant's Masonry Wall Program conforms to the recommended GALL AMP XI.S5.

3.0.3.1.7.3 Exceptions to the GALL Report

None

3.0.3.1.7.4 Enhancements

None

3.0.3.1.7.5 Operating Experience

The applicant stated, in the OCGS LRA and the program basis document, that the Masonry Wall Program has provided for detection of cracks, and other minor aging effects in masonry walls. Maintenance history revealed minor degradation of masonry block walls; but none that could impact their intended function. Oyster Creek masonry walls that perform an intended function under 10 CFR 54.4 have been systematically identified in accordance with the scoping and screening methodology described in the LRA. The walls include walls identified in response to NRC Bulletin 80-11, USI A-46, and those that perform 10 CFR 54.48 intended function. Review of industry operating experience has confirmed that cracking of masonry walls has occurred in the past (NRC Bulletin No. 80-11; NRC IN 87-67. In response to NRC Bulletin 80-11, ?Masonry Wall Design," and IN 87-67, ?Lessons Learned from Regional Inspections of Licensee Actions in Response to Bulletin 80-11," various actions were taken. Actions included modifications of some walls and removal of others, program enhancements, follow-up inspections to substantiate masonry walls analyses and classifications, and the development of procedures for tracking and recording changes to the walls. These actions addressed all concerns raised by Bulletin 80-11 and IN 87-67, namely unanalyzed conditions, improper assumptions, improper classification, and lack of procedural controls.

The applicant's operating experience review process includes both external and internal sources. External operating experience may include such things as INPO documents (e.g., SOERs, SERs, SENs, etc.), NRC documents (e.g., GLs, LERs, INs, etc.), General Electric documents (e.g., RCSILs, SILs, TILs, etc.), and other documents (e.g., 10CFR Part 21 Reports, NERs, etc.). Internal operating experience may include such things as event investigations, trending reports, and lessons learned from in-house events as captured in program notebooks, self-assessments, and in the 10 CFR Part 50, Appendix B corrective action process.

The applicant provided the following examples of operating experience to provide objective evidence that the Masonry Wall Program is effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

> CAP No. 02003-0038 was issued to document and evaluate degraded and missing mortar between masonry blocks on a fire barrier masonry wall in the lower cable spreading room. The degraded and missing mortar was evaluated by the qualified structural engineer and the fire protection engineer. The structural engineer concluded that the degraded and missing mortar does not adversely impact the masonry wall structural integrity. The fire protection engineer concluded that the observed condition of the fire barrier masonry wall does not render the barrier inoperable. Action Request #A2052336 was generated to repair the masonry wall and restore it to its design condition.
>
> CAP No. 02002-0065 was issued to document and evaluate small cracks in a fire barrier masonry wall in the turbine building. The cracks were evaluated by the qualified structural engineer and the fire protection engineer. The structural engineer concluded that the small cracks have no impact on the structural integrity of the masonry wall. The fire protection engineer determined that the cracks do not impact the fire barrier intended function of the masonry wall.

The applicant concluded that the operating experience of the Masonry Wall Program did not show any adverse trend in performance. Problems identified would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. There is sufficient confidence that the implementation of the Masonry Wall Program will effectively determine cracking. Appropriate guidance for reevaluation, repair or replacement is provided for locations where cracking has occurred. Periodic self-assessments of the Masonry Wall Program are performed to identify the areas that need improvement to maintain the quality performance of the program.

The project team reviewed the operating experience provided in the OCGS LRA and the program basis document, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant’s Masonry Wall Program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.1.7.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the Masonry Wall Program in OCGS LRA, Appendix A, Section A.1.30, which states that the Masonry Wall Program manages aging effects so that the evaluation basis established for each masonry wall WSLR remains valid through the period of extended operation. The applicant’s Masonry Wall Program is based on the structures monitoring requirements of 10 CFR 50.65. The applicant’s Masonry Wall Program is implemented by its structures monitoring program for managing specific aging effects.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.30, found that it was consistent with the GALL Report, and determined that it provided an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.1.7.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that all the program elements are consistent with the GALL Report. On the basis of its review of the UFSAR Supplement for this program, the project team found that it provided an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.8 Protective Coating Monitoring and Maintenance Program (OCGS AMP B.1.33)

In OCGS LRA, Appendix B, Section B.1.33, the applicant stated that OCGS AMP B.1.33, "Protective Coating Monitoring and Maintenance Program," is an existing plant program that is consistent with GALL AMP XI.S8, "Protective Coating Monitoring and Maintenance Program."

3.0.3.1.8.1 Program Description

The applicant stated, in the OCGS LRA, that this program provides for aging management of Service Level I coatings inside the primary containment and Service Level II coatings for the external drywell shell in the area of the sand bed region. Service Level I coatings are used in areas where the coating failure could adversely affect the operation of post-accident fluid systems and thereby impair safe shutdown. Oyster Creek was not originally committed to Regulatory Guide 1.54 for Service Level I coatings because the plant was licensed prior to the issuance of this Regulatory Guide in 1974. Currently, Oyster Creek is committed to a modified version of this Regulatory Guide, as described in the response to GL 98-04, and, as detailed in the Exelon Quality Assurance Topical Report (QATR) NO-AA-10. Service Level II coatings provide corrosion protection and decontaminability in those areas outside of the primary containment that are subject to radiation exposure and radionuclide contamination. The Protective Coating Monitoring and Maintenance Program provides for visual inspections, assessment, and repairs for any condition that adversely affects the ability of Service Level I coatings, or sand bed region Service Level II coatings, to function as intended.

3.0.3.1.8.2 Consistency with the GALL Report

In OCGS LRA, the applicant stated that OCGS AMP B.1.33 is consistent with GALL AMP XI.S8.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.33, including PBD-AMP-B.1.33, ?OCGS Program Basis Document: Protective Coating Monitoring and Maintenance Program," Rev. 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.S8. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained OCGS AMP B.1.33 and associated bases documents to determine their consistency with GALL AMP XI.S8.

The project team also reviewed SP-1302-52-120, "Specification for Inspection and Localized Repair of the Torus and Vent System Coating", Rev. 2, July 2003, and Calculation C-1302-187-E310-038, ?Oyster Creek Torus Corrosion Allowable Pit Depth", Rev. 0, October 2002.

The project team noted that the description of AMP B.1.33 in the LRA is not completely clear about which coatings are credited for corrosion protection of metal surfaces. In response to a question, the applicant clarified that Service Level 2 coatings are used only for corrosion protection in the external drywell shell sand bed region. Similarly, while some service Level 1 coatings are used to provide corrosion protection, Oyster Creek does not credit them for corrosion protection for the drywell shell above the sand bed region for license renewal purposes. An analysis has been performed which demonstrates that the upper portion of the drywell vessel will meet ASME code requirements for the remaining life of the plant based on corrosion rates. The corrosion of the drywell shell above the sand bed region is considered a TLAA and is further described in LRA Section 4.7.2. However, Service Level 1 coatings are credited for corrosion protection for the vent header and torus.

The applicant further stated in response to an audit question that for LOCA debris generation and transport, the drywell coating is qualified for a LOCA environment. The mass of coating released following a LOCA jet impingement was conservatively estimated at 47 lbs. No additional coating flaking was assumed due to the harsh environment since the coating is qualified. Coating within the vent system and torus is expected to contribute 0 lbs of debris to the suction strainer load following a LOCA. However, the applicant conservatively assumed in the analysis that 10 lbs of debris is attributed to the vent system and torus coating.

The project team also asked the applicant to clarify whether any Service Level III coatings are credited for corrosion protection for license renewal. In response, the applicant stated that Exelon Corporate Procedure ER-AA-330-008 in paragraph 2.7.3 defines Service Level III coatings as coatings used on any exposed surface area located outside containment whose failure could adversely affect normal plant operation, or orderly and safe plant shutdown. Service Level III coatings are also used in areas outside the reactor containment where failure could adversely affect the safety function of a safety-related structure, system, or component. Oyster Creek Specification SP-9000-06-004, in paragraph 3.2.1.c, specifies the use of Service Level III coatings on structures/components subjected to a corrosive environment (e.g., liquid immersion, saltwater contact, underground burial, outdoor exposure, etc.). For license renewal, Service Level III coatings are only credited for corrosion protection for the external surfaces of piping and fittings exposed to a soil (external) environment in the emergency service water system, service water system, and roof drain and overboard discharge system. These coatings are managed under the Buried Piping Inspection aging management program, B.1.26. Other than the Service Level I and II coatings discussed in PBD-AMP-B.1.33, and the Service Level III coatings described in response to this question, no other protective coatings are credited for corrosion protection for license renewal.

The project team also noted that the discussion in LRA Table 3.5.1, Item Number 3.5.1-15, appears to identify a larger scope than the scope identified in the AMP description. The project team asked the applicant to clarify this. In response, the applicant stated that the structures and/or components and environments "rolled-up" into LRA Table 3.5.1 Item Number 3.5.1-15 (reference LRA Table 3.5.2.1.1 for primary containment) include the following:

- Access hatch covers – containment atmosphere (internal)
- Downcomers – containment atmosphere
- Drywell penetration sleeves – containment atmosphere (internal)
- Drywell shell – containment atmosphere (internal) and indoor air (external)
- Personnel airlock/equipment hatch – containment atmosphere (internal)
- Suppression chamber penetrations – containment atmosphere (internal)
- Suppression chamber ring girders – containment atmosphere (external)
- Suppression chamber shell – containment atmosphere (internal)
- Vent line, and vent header – containment atmosphere (internal) and indoor air (external)
- Downcomers – immersed
- Suppression chamber ring girders – immersed
- Suppression chamber penetrations – immersed
- Suppression chamber shell – immersed

The applicant stated that for Service Level I coatings, the Protective Coating Monitoring and Maintenance Program is not used to manage loss of material for access hatch covers, drywell penetration sleeves, and personnel airlock/equipment hatch exposed to a containment atmosphere (internal) environment. Accordingly, LRA Table 3.5.2.1.1 for the primary containment will be revised to delete the Protective Coating Monitoring and Maintenance Program (B.1.33) from these component types exposed to a containment atmosphere environment. For Service Level II coatings, the Protective Coating Monitoring and Maintenance Program is not used to manage corrosion for the vent line, and vent header exposed to an indoor air (external) environment. Accordingly, LRA Table 3.5.2.1.1 and Table 3.5.1, item 3.5.1-15, will be revised to delete the Protective Coating Monitoring and Maintenance Program (B.1.33) from this component type exposed to an indoor air environment.

In its letter dated April 17, 2006 (ML061150320), the applicant committed to revise LRA Tables 3.5.2.1.1 and 3.5.1 to delete the Protective Coating Monitoring and Maintenance Program (B.1.33) from line items to manage loss of material for access hatch covers, drywell penetration sleeves, and personnel airlock/equipment hatch exposed to a containment atmosphere (internal) environment, and line items to manage corrosion for the vent line, and vent header exposed to an indoor air (external) environment. This is identified as **Audit Commitment 3.0.3.1.8-1.**

The project team found the applicant's clarifications acceptable, because they defined the scope of coatings credited for corrosion protection, and also defined the coatings that are specifically monitored and maintained by AMP B.1.33 for license renewal.

During its review of plant-specific operating experience related to containment degradation, the project team asked a number of questions about the implementation of AMP B.1.33 for the exterior surface of the sand bed region and for the submersed interior surface of the torus. The project team's inquiries and assessments of the applicant's responses are documented in the evaluation of the applicant's ASME Section XI, Subsection IWE program (B.1.27), in Section 3.0.3.2.22 of this audit and review report.

The project team reviewed those portions of the applicant's Protective Coating Monitoring and Maintenance Program for which the applicant claims consistency with GALL AMP XI.S8.

3.0.3.1.8.3 Exceptions to the GALL Report

None

3.0.3.1.8.4 Enhancements

Although the LRA did not identify any enhancements for AMP B.1.33, PBD-AMP-B.1.33, ?OCGS Program Basis Document: Protective Coating Monitoring and Maintenance Program," Rev. 0, identified the following enhancement in order to meet the GALL program elements:

Elements: 3. Parameters Monitored or Inspected
4. Detection of Aging Effects
6. Acceptance Criteria

Enhancement: ?The inspection of Service Level I and Service Level II protective coatings that are credited for mitigating corrosion on interior surfaces of the Torus shell and vent system, and, on exterior surfaces of the Drywell shell in the area of the sand bed region, will be consistent with ASME Section XI, Subsection IWE requirements."

The GALL Report includes the following recommendations for the ?parameters monitored or inspected," ?detection of aging effects," and ?acceptance criteria" program elements related to the enhancement stated:

3. *Parameters Monitored or Inspected*: Regulatory Position C4 in RG 1.54, Rev. 1, states that "ASTM D 5163-96 provides guidelines that are acceptable to the NRC staff for establishing an in-service coatings monitoring program for Service Level I coating systems in operating nuclear power plants..." ASTM D 5163-96 has been superseded by

ASTM D 5163-05. ASTM D 5163-05, subparagraph 10.2, identifies the parameters monitored or inspected to be "any visible defects, such as blistering, cracking, flaking, peeling, rusting, and physical damage."

4. *Detection of Aging Effects*: ASTM D 5163-05, paragraph 6, defines the inspection frequency to be each refueling outage or during other major maintenance outages as needed. ASTM D 5163-05, paragraph 9, discusses the qualifications for inspection personnel, the inspection coordinator and the inspection results evaluator. ASTM D 5163-05, subparagraph 10.1, discusses development of the inspection plan and the inspection methods to be used. It states, "A general visual inspection shall be conducted on all readily accessible coated surfaces during a walk-through. After a walkthrough, or during the general visual inspection, thorough visual inspections shall be carried out on previously designated areas and on areas noted as deficient during the walk-through. A thorough visual inspection shall also be carried out on all coatings near sumps or screens associated with the Emergency Core Cooling System (ECCS)." This subparagraph also addresses field documentation of inspection results. ASTM D 5163-05, subparagraph 10.5, identifies instruments and equipment needed for inspection.

6. *Acceptance Criteria*: ASTM D 5163-05, subparagraphs 10.2.1 through 10.2.6, 10.3 and 10.4, contain one acceptable method for characterization, documentation, and testing of defective or deficient coating surfaces. Additional ASTM and other recognized test methods are available for use in characterizing the severity of observed defects and deficiencies. The evaluation covers blistering, cracking, flaking, peeling, delamination, and rusting. ASTM D 5163-05, paragraph 12, addresses evaluation. It specifies that the inspection report is to be evaluated by the responsible evaluation personnel, who prepare a summary of findings and recommendations for future surveillance or repair, including an analysis of reasons or suspected reasons for failure. Repair work is prioritized as major or minor defective areas. A recommended corrective action plan is required for major defective areas, so that these areas can be repaired during the same outage, if appropriate.

The inclusion of this enhancement in B.1.33 resulted from discussions between the project team and the applicant during the October 3-7, 2005 on-site audit. At that time, the applicant indicated its intention to use the Protective Coating Monitoring and Maintenance Program in lieu of the requirements of ASME Section XI, Subsection IWE, for inspection of coatings. The project team noted that a Protective Coating Monitoring and Maintenance Program can be credited for corrosion mitigation, but is not a substitute for IWE inspection requirements. On this basis, the applicant committed to implement the applicable IWE requirements for containment coatings inspection in its Protective Coating Monitoring and Maintenance Program. The project team asked the applicant to clarify what changes are necessary to make the Protective Coating Monitoring and Maintenance Program consistent with ASME Section XI, Subsection IWE requirements. In its response, the applicant stated that the requirements for coating inspections are included in Oyster Creek specifications: SP-1302-52-120, "Specification for Inspection and Localized Repair of the Torus and Vent System Coating" and IS-328227-004, "Functional Requirements for Drywell Containment Vessel Thickness Examination." These specifications do not currently invoke all of the requirements of ASME Section XI, Subsection IWE. The following requirements will be included in these inspection specifications:

1. Torus and vent system internal coating inspections will be per Examination Category E-A and will require VT-3 visual examinations per IWE-3510.2. The inspected area shall be examined (as a minimum) for evidence of flaking, blistering, peeling, discoloration, and other signs of distress. Areas that are suspect shall be dispositioned by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122. Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of engineering evaluation.

2. Sand bed Region external coating inspections will be per Examination Category E-C (augmented examination) and will require VT-1 visual examinations per IWE-3412.1. The inspected area shall be examined (as a minimum) for evidence of flaking, blistering, peeling, discoloration, and other signs of distress. Areas that are suspect shall be dispositioned by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122. Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of engineering evaluation.

In its letter dated April 4, 2006 (ML060970288), the applicant committed to the following: The coating inside the torus will be visually inspected in accordance with ASME Section XI, Subsection IWE, per the protective coatings program. This commitment will be performed every other refueling outage prior to and during the period of extended operation. This is **Audit Commitment 3.0.3.1.8-2.**

The project team finds this enhancement to the Protective Coating Monitoring and Maintenance Program to be acceptable, because it ensures that the requirements of IWE related to coatings inspection will be implemented during the extended period of operation.

3.0.3.1.8.5 Operating Experience

The applicant stated, in the OCGS LRA and the program basis document, that Oyster Creek has successfully identified indications of age-related degradation in Service Level I coatings prior to the loss of intended functions and has taken appropriate corrective actions through evaluation or repair in accordance with the Service Level I coatings procedures and specifications. The applicant further stated that the Service Level II coating effort completed in 14R has been effective in mitigating corrosion in the sand bed area.

The applicant stated that Oyster Creek was not originally committed to Regulatory Guide 1.54 because the plant was licensed prior to the issuance of this Regulatory Guide in 1974. Currently, Oyster Creek is committed to a modified version of this Regulatory Guide, as described in the Oyster Creek response to GL 98-04, and, as detailed in the Exelon Quality Assurance Topical Report (QATR) NO-AA-10. Oyster Creek's response to GL 98-04 satisfies the recommendations for an acceptable coatings maintenance aging management program (AMP) for license renewal as identified in the "Program Description" paragraph of NUREG-1801 Chapter XI program XI.S8. The Oyster Creek program for monitoring and maintaining Service Level I coatings inside containment is implemented through specification of appropriate technical and quality recommendations of RG 1.54, Rev. 0, and American National Standards Institute (ANSI) N101.2, "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities," and N101.4, "Quality Assurance for Protective Coatings Applied to Nuclear Facilities." The guidance provided in Electric Power Research Institute (EPRI) Technical Report TR-109937, "Guidelines on Nuclear Safety-Related Coating" has been evaluated and improvements have been implemented to the program as appropriate. The experience at Oyster Creek with the Protective Coating Monitoring and Maintenance Program aging management program shows that the program is effective in managing Service Level I protective coatings inside the containment, and, in managing Service Level II coatings on the external drywell shell in the area of the sand bed region.

The applicant stated that operating experience from both external and internal (also referred to as in-house) sources is reviewed. External operating experience may include such things as INPO documents (e.g., SOERs, SERs, SENs, etc.), NRC documents (e.g., GLs, LERs, INs, etc.), General Electric documents (e.g., RCSILs, SILs, TILs, etc.), and other documents (e.g., 10CFR Part 21 Reports, NERs, etc.). Internal operating experience may include such things as event investigations, trending reports, and lessons learned from in-house events as captured in program notebooks, self-assessments, and in the 10 CFR Part 50, Appendix B corrective action process.

The applicant described the following examples of operating experience as objective evidence that the Protective Coating Monitoring and Maintenance Program aging management program is effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

> (1) <u>Drywell</u>: The Oyster Creek drywell interior surfaces above the concrete floor, including jet deflectors, and the exterior of the drywell above the water seal support bracket were originally coated with one coat of Carboline Carbo-Zinc 11 paint. The interior surface of the drywell below el. 12'-3" and the exterior surface of the drywell in direct contact with final support concrete was not painted. The potential for corrosion of the drywell vessel was first recognized when water was noticed coming from the sand bed drains in 1980. Corrosion was later confirmed by ultrasonic thickness (UT) measurements taken in 1986 during the 11R refueling outage. During the 12R refueling outage in 1988, the first extensive corrective action, installation of a cathodic protection system, was taken. This proved to be ineffective. The system was removed during the 14R refueling outage in 1992. The upper regions of the vessel, above the sand bed, were handled separately from the sand bed region because of the significant difference in corrosion rate and physical difference in design. Corrective action for the upper vessel involved providing a corrosion allowance by demonstrating, through analysis, that the original drywell design pressure was conservative. Amendment 165 to the Oyster Creek Technical Specification reduced the drywell design pressure from 62 psig to 44 psig. The new design pressure coupled with measures to prevent water intrusion into the gap between the vessel and the concrete will allow the upper portion of the vessel to meet ASME code for the remainder life of the plant.
>
> In the sand bed region, laboratory testing determined the corrosion mechanism to be galvanic. The high rate of corrosion in this region required prompt corrective action of a physical nature. Corrective action was defined as; (1) removal of sand to break up the galvanic cell, (2) removal of the corrosion product from the vessel and (3) application of a protective coating. Keeping the vessel dry was also identified as a requirement even though it would be less of a concern in this region once the coating was applied. The work was initiated during the 12R refueling outage in 1988 by removing sheet metal from around the vent headers to provide access to the sand bed from the Torus room. During operating cycle 13 some sand was removed and access holes were cut into the sand bed region through the shield wall. The work was finished during the 14R refueling outage in 1992.

After sand removal, the concrete floor was found to be unfinished with improper provisions for water drainage. Corrective actions taken in this region during the 14R refueling outage in 1992 included; (1) cleaning of loose rust from the drywell shell, followed by application of epoxy coating and (2) removing the loose debris from the concrete floor followed by rebuilding and reshaping the floor with epoxy to allow drainage of any water that may leak into the region.

During 14R, UT measurements were taken from the outside surface of the drywell vessel in the sand bed region. Measurements were taken in each of the ten sand bed bays. The results of this inspection and the structural evaluation of the "as found" condition of the vessel are contained in TDR No. 1108, "Summary Report of Corrective Action Taken from Operating Cycle 12 Through 14R", Revision 0. As documented in TDR No. 1108, the vessel was evaluated to conform to ASME code requirements given the deteriorated thickness condition. In general these measurements verified projections that had been made based on measurements taken from inside the drywell. Several areas were thinner than projected. In all cases, the applicant found these areas met ASME code requirements after structural analysis.

The coated surfaces of the former sand bed region have been subsequently inspected during refueling outages in 1994, 1996, 2000, and 2004 as documented in DCR 05-00023-00 Attachment 1, Page 12, paragraph 7.8.1.3.1. The inspections showed no coating failure or signs of deterioration. The applicant therefore concluded that the cleaning, floor refurbishing and coating effort completed in 14R has been effective in mitigating corrosion in the sand bed area. Since this was accomplished while the vessel thickness was sufficient to satisfy ASME code requirements, the applicant has concluded that drywell vessel corrosion in the sand bed region is no longer a limiting factor in plant operation; however, inspections are conducted to ensure that the coating remains effective. In addition, UT measurements are also taken from inside the drywell. The frequency and extent of the coating inspections and UT thickness measurements are as follows:

- For the upper elevations, UT measurements are taken every second refueling outage. After each inspection, a determination will be made if additional inspection is to be performed. Although protective coating is not credited for corrosion mitigation in these areas, the coating is inspected to ensure its integrity for the purpose of maintaining ECCS suction strainer debris loading assumptions.

- For the sand bed region, visual inspection of the coating is performed every second refueling outage. After each inspection, a determination will be made if additional inspection is to be performed.

- For water leakage not associated with refueling activities, an investigation will be made as to the source of the leakage. Oyster Creek will take corrective actions, evaluate the impact of the leakage and, if necessary, perform an additional drywell inspection about three months after the discovery of the water leakage.

Calculation Number C-1302-187-E310-037, "Statistical Analysis of Drywell Vessel Thickness Data," Revision 2, provides the evaluation of the latest drywell UT inspections performed by IS-328227-004 (through November 2004). Oyster Creek has committed to notify the NRC prior to implementing any changes to the drywell thickness measurement inspection program.

The drywell coating history and operating experience provides objective evidence that previous corrective actions have been effective in mitigating corrosion in the sand bed region and that the Protective Coating Monitoring and Maintenance Program aging management program is effectively implemented to ensure that the intended function of systems, structures, and components within the scope of license renewal will be maintained during the extended period of operation.

(2) Torus and Vent Systems: The Oyster Creek torus and vent system were originally coated with one coat of Carboline Carbo-Zinc 11 paint. In 1983, the Torus interior surfaces, the interior of the Vent System up to the drywell and all external surfaces of the Vent System were grit blasted to SSPC-10 or SSPC-5 at 1 ½ – 3 mils profile.

Pitted surfaces of immersed Torus shell were repaired by welding. Rough areas of Torus shell were blended by grinding. Mobil 46-X-16 Epoxy Filler was applied to selected pitted areas of the Torus immersed shell portion prior to coating. Surfaces in the Vent System thinned by corrosion were repaired by welding.

The immersed bottom half of the torus shell, the interior of the downcomer and the entire interior surfaces of the Vent System were given 3 coats of Mobil 78 Hi-Build Epoxy (DFT-16 mils). The vapor phase upper half of the torus shell, exterior of the Vent Header and vent lines portions inside the torus were given two coats of Mobil 78-Hi Build epoxy (DFT-10 mils).

Following coating application, the entire torus interior was heat cured at 108˚F for 48 hours. Demineralized water was put back in the torus. Subsequent to this coating application, minor coating repairs have been performed using BRUTEM-15 (UT-15).

De-sludging, inspection, and repair of the interior coating of the torus shell and vent system located above and below the water line is performed during refueling outages in accordance with Specification SP-1302-52-120. Torus and vent header vapor space Service Level I coating inspections performed in 2002 found the coating in these areas to be in good condition. Inspection of the immersed coating in the torus identified blistering. The blistering occurred primarily in the shell invert but was also noted on the upper shell near the water line. The majority of the blisters remained intact and continued to protect the base metal. However, several blistered areas included pitting damage where the blisters were fractured. A qualitative assessment of the identified pits was performed and concluded that the measured pit depths were significantly less than the established acceptance criteria. The fractured blisters were repaired to reestablish the protective coating barrier.

The torus and vent system coating history and operating experience provides objective evidence that previous corrective actions have been effective in mitigating corrosion in the torus and vent system and that the Protective Coating Monitoring and Maintenance Program aging management program is effectively implemented to ensure that the intended function of systems, structures, and components within the scope of license renewal will be maintained during the extended period of operation.

(3) Miscellaneous OE: CAP No. O2000-1429 identified that a modification was to add approximately 28 square feet of hot dipped galvanized unistrut steel to the drywell. Specification SP-1302-06-009, "Specification for Application and Repair of Service Level I Coatings on Ferrous Metal Surfaces Oyster Creek Nuclear Generating Station," Appendix A, for approved coatings inside the primary containment, does not include galvanized coating as an approved coating. An evaluation performed by the engineering group concluded that a) DBA conditions will not adversely affect galvanized surfaces or the functioning of safety systems, b) hot dipped galvanized surfaces are not required to be DBA tested by any code, standard, or regulation, and c) the addition of this galvanized unistrut steel to the drywell was acceptable. This example provides objective evidence that the addition of unqualified coatings to the primary containment are evaluated for impact on safety-related systems and structures.

CAP No. O2003-2454 identified that the replacement motor for the "A" recirculation motor was top coated with a non-DBA qualified coating on the motor housing, end bells, and stator. Engineering analysis concluded that the unqualified coating would minimally impact the strainer debris loading following a postulated LOCA and that any additional head loss created by the additional unqualified coating was negligible. This example provides objective evidence that the addition of unqualified coatings to the primary containment is evaluated for impact on safety-related systems and structures.

In summary, the operating experience of the Protective Coating Monitoring and Maintenance Program aging management program did not show any adverse trend in performance. Problems identified would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. The applicant has sufficient confidence that the implementation of the Protective Coating Monitoring and Maintenance Program aging management program will effectively manage Service Level I coatings inside the primary containment and Service Level II coatings for the external drywell shell in the area of the sand bed region.

The project team reviewed the above operating experience provided in the LRA and the B.1.33 program basis document, and also interviewed the applicant's technical staff. The project team determined that the OCGS plant-specific operating experience with containment degradation is unique, and is not bounded by industry experience. As discussed above, in Section 3.0.3.1.8.2 of this audit and review report, the project team's review of operating experience led to a number of questions about the implementation of AMP B.1.33. As a result of these inquiries, the project team identified an audit open item.

3.0.3.1.8.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the Protective Coating Monitoring and Maintenance Program in OCGS LRA, Appendix A, Section A.1.33, which states that the Protective Coating Monitoring and Maintenance Program is an existing program that provides for aging management of Service Level I coatings inside the primary containment and Service Level II coatings for the external drywell shell in the area of the sand bed region. Service Level I coatings are used in areas where the coating failure could adversely affect the operation of post accident fluid systems and thereby impair safe shutdown. Oyster Creek was not originally committed to Regulatory Guide 1.54 for Service Level I coatings because the plant was licensed prior to the issuance of this Regulatory Guide in 1974. Currently, Oyster Creek is committed to a modified version of this Regulatory Guide, as described in the response to GL 98-04, and, as detailed in the Exelon Quality Assurance Topical Report (QATR) NO-AA-10.

Service Level II coatings provide corrosion protection and decontaminability in those areas outside of the primary containment that are subject to radiation exposure and radionuclide contamination. The Protective Coating Monitoring and Maintenance Program provides for inspections, assessment, and repairs for any condition that adversely affects the ability of Service Level I coatings, or sand bed region Service Level II coatings, to function as intended.

In its letter dated April 4, 2006, the applicant committed to the following:

- Implement the applicable ASME Section XI, Subsection IWE requirements for containment coatings inspection in its Protective Coating Monitoring and Maintenance Program. (Audit Commitment 3.0.3.1.8-2)

In its letter dated April 17, 2006, the applicant committed to the following:

- Revise LRA Tables 3.5.2.1.1 and 3.5.1 to delete the Protective Coating Monitoring and Maintenance Program (B.1.33) from line items to manage loss of material for access hatch covers, drywell penetration sleeves, and personnel airlock/equipment hatch exposed to a containment atmosphere (internal) environment, and line items to manage corrosion for the vent line, and vent header exposed to an indoor air (external) environment. (Audit Commitment 3.0.3.1.8-1)

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.33. Contingent upon the inclusion of audit commitments 3.0.3.1.8-1, 3.0.3.1.8-2 and resolutions to open item 3.0.3.2.22-3, the project team found that it was consistent with the GALL Report, and determined that it provided an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.1.8.7 Conclusion

On the basis of its audit and review of the applicant's program and the plant-specific operating experience and discussions with the applicant's technical staff, the project team initiated open item 3.0.3.2.22-3 for primary containment (drywell) for further evaluation of the applicant’s Protective Coating Monitoring and Maintenance Program.

On the basis of its review of the UFSAR Supplement for this program, the project team found that, contingent upon the inclusion of commitments 3.0.3.1.8-1, 3.0.3.1.8-2, and resolutions to open item 3.0.3.2.22-3, it provided an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.9 Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (OCGS AMP B.1.34)

In OCGS LRA, Appendix B, Section B.1.34, the applicant stated that OCGS AMP B.1.34, ?Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements,” is a new plant program that will be consistent with GALL AMP XI.E1, ?Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.”

3.0.3.1.9.1 Program Description

In the OCGS LRA, the applicant stated that this program will be used to manage non-EQ cables and connections within the scope of license renewal that are subject to adverse localized environments. The applicant stated that an adverse localized environment is a condition in a limited plant area that is significantly more severe than the specified service environment for a subject cable or connection. An adverse variation in the environment is significant if it could appreciably increase the rate of aging of a component or have an immediate adverse effect on operability.

The applicant also stated that cables and connections subject to an adverse environment are managed by inspection of these components. A sample of accessible electrical cables and connections installed in adverse localized environments will be visually inspected for signs of accelerated age-related degradation such as embrittlement, discoloration, cracking, or surface contamination. Additional inspections, repairs, or replacements are initiated as appropriate.

The applicant further stated that accessible cables and connections located in adverse localized areas will be inspected before the period of extended operation, with an inspection frequency of at least once every 10 years. The scope of this program includes inspections of power, control and instrumentation cables, and connections located in adverse localized areas.

3.0.3.1.9.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.34 is consistent with GALL AMP XI.E1.

The project team interviewed the applicant’s technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.34, including program basis document (PBD) PBD-AMP-B.1.34, ?Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements,” Revision 0, which assesses the AMP elements’ consistency with GALL AMP XI.E1. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.34 and associated bases documents to determine their consistency with GALL AMP XI.E1.

The project team reviewed those portions of the applicant’s Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, for which the applicant claims consistency with GALL AMP XI.E1, and found that they are consistent with this GALL Report AMP. The project team found that the applicant’s Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program conforms to the recommended GALL AMP XI.E1.

3.0.3.1.9.3 Exceptions to the GALL Report

None

3.0.3.1.9.4 Enhancements

None

3.0.3.1.9.5 Operating Experience

In the OCGS LRA, the applicant stated that the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is a new program. A review of plant-specific operating experience revealed instances of potential age-related degradation of cables identified during routine maintenance activities. These were remedied using the corrective action program. In each case, engineering evaluations determined the cause of the apparent degradation, the effect on operability, and the appropriate corrective action.

The project team also reviewed the operating experience provided in the OCGS LRA and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

The staff believes that the corrective action process will capture internal and external plant operating issues to ensure that aging effects are adequately managed.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant's Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.1.9.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program in Section A.1.34 of Appendix A to the OCGS LRA, which states that the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is a new program that will be used to manage the aging of non-EQ cables and connections during the period of extended operation. A representative sample of accessible cables and connections located in adverse localized environments will be visually inspected at least once every 10 years for indications of accelerated insulation aging such as embrittlement, discoloration, cracking, or surface contamination. An adverse localized environment is a condition in a limited plant area that is significantly more severe than the specified service environment for a subject electrical cable or connection.

The project team also reviewed the license renewal commitment list in Section A.5 of the OCGS LRA to confirm that this program will be implemented before the period of extended operation and noted that it is Item 34 on the list of commitments.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.34, found that it was consistent with the GALL Report, and determined that it provided an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.1.9.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those portions of the program for which the applicant claims consistency with the GALL Report are consistent with the GALL Report. On the basis of its review of the UFSAR Supplement for this program, the project team found that it provided an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.10 Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (OCGS AMP B.1.36)

In OCGS LRA, Appendix B, Section B.1.36, the applicant stated that OCGS AMP B.1.36, ?Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," is a new plant program that is consistent with GALL AMP XI.E3, ?Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

3.0.3.1.10.1 Program Description

In the OCGS LRA, the applicant stated that this new program will manage inaccessible medium-voltage cables that are exposed to significant moisture simultaneously with significant voltage.

The applicant stated that significant moisture is defined as periodic exposures to moisture that lasts more than a few days (e.g., a cable in standing water). Periodic exposures to moisture that lasts less than a few days (e.g., normal rain and drain) are not significant. Significant voltage exposure is defined as being subjected to system voltage for more than 25 percent of the time.

The applicant further stated that OCGS has a total of 47 medium-voltage cable installations. Because of the history of medium-voltage cable failures at OCGS, all 47 cable circuits are conservatively assumed to have the potential to be exposed to significant moisture conditions. Furthermore, all are conservatively assumed to be energized more than 25 percent of the time. Consequently, all 47 medium-voltage cable circuits are included in the scope of the Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program.

The applicant stated that this program will also inspect manholes, conduits, and sumps associated with the 47 cable circuits (2.4 kV and 4.16 kV) for water collection so that draining or other corrective actions can be taken. Inspections for water collection will be performed at least once every 2 years, and the frequency of testing will be adjusted based on the results obtained. The first inspections will be completed before the period of extended operation.

In addition, these medium-voltage cable circuits will be examined using a proven test for detecting deterioration of the insulation system resulting from wetting, such as power factor, partial discharge, or polarization index, as described in EPRI TR-103834- P1-2, or other testing that is state-of-the-art at the time the test is performed. Cable testing will be performed at least once every 10 years, and the frequency of testing will be adjusted depending on the results obtained. The first tests will be completed before the period of the extended operation. The applicant stated that current methodologies at OCGS implement a polarization index test as part of step voltage and megger testing, and the applicant does not currently use, nor does it plan to use in the future, polarization index testing as the lone condition monitoring test in its AMP B.1.36.

In its letter dated April 17, 2006 (ML061150320), the applicant committed to revise AMP B.1.36 in the OCGS LRA to clarify that the applicant does not use polarization index testing as the lone condition monitoring test for medium-voltage cable circuits. **This is Audit Commitment 3.0.3.1.10-1**.

In NRC Request for Additional Information (RAI) 2.5.1.19-1, dated September 28, 2005, the staff expressed the need for additional information to continue its review of long-lived passive components of the Forked River combustion turbines (FRCTs). By letters dated October 12, 2005, and November 11, 2005, the applicant provided its responses. The AMP B.1.36 program scope has been revised to include 13.8 kV inaccessible medium-voltage cables associated with the FRCTs. In addition, as a result of the applicant's reconciliation of the September 2005 revision of NUREG-1801 to the January 2005 draft revision, 34.5 kV system cables will be added to this program.

In its letter dated March 30, 2006 (ML060950408), the applicant committed to revise AMP B.1.36 in the OCGS LRA to include 34.5 kV system cables in the program. This commitment will be added to the Table A.5 License Renewal Commitment List Item No. 36. **This is Audit Commitment 3.0.3.1.10-2**.

3.0.3.1.10.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.36 is consistent with GALL AMP XI.E3.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.36, including PBD-AMP-B.1.36, ?Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," which assesses the AMP elements' consistency with GALL AMP XI.E3. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.36 and associated bases documents to determine their consistency with GALL AMP XI.E3.

The project team reviewed those portions of the applicant's Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program for which the applicant claims consistency with GALL AMP XI.E3 and found that they are consistent with this GALL Report AMP. The project team found that the applicant's Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program conforms to the recommended GALL AMP XI.E3.

3.0.3.1.10.3 Exceptions to the GALL Report

None

3.0.3.1.10.4 Enhancements

None

3.0.3.1.10.5 Operating Experience

In the OCGS LRA, the applicant stated that it has experienced 11 inservice medium-voltage circuit failures to date. Five resulted from water intrusion, four from manufacturing defects, and two from a single lightning strike. The majority of those failures occurred in EPR-insulated ?UniShield" cables manufactured by Anaconda before 1985. In 1991, the applicant implemented a medium-voltage cable testing program covering its 2.3 kV and 4.1 kV medium-voltage circuits in an attempt to identify cable degradation so that appropriate corrective action could be taken before failure. That inspection program successfully identified degradation in XLPE-insulated cables before failure. However, the inspection program failed to identify degradation in the EPR-insulated cables prior to failure. Testing performed under the current cable testing program successfully identified degradation in XLPE-insulated cables (e.g., GE Vulkene) such that replacements could be made before inservice failures. Eleven XLPE-insulated cable circuit replacements have been made based on test results since the testing program was implemented in 1991. No inservice failures of XLPE-insulated cable have occurred since the testing program was implemented in 1991.

Testing performed under the current cable testing program has not successfully identified degradation in EPR-insulated UniShield type cables (e.g., Anaconda UniShield), such that replacements could be made before inservice failures. Five inservice failures of UniShield cable circuits exposed to moisture have occurred since the testing program was implemented in 1991. Four of the five failed cables were manufactured before UniShield manufacturing process improvements were implemented in mid-1984 to address manufacturing defects.

Following the most recent inservice cable failure in 2003, the applicant completed corrective actions to (1) test failed cables to confirm the failure mechanisms, (2) confirm the accuracy of configuration information for 4160V circuits, (3) evaluate all remaining UniShield cables and replace or schedule for replacement those manufactured before 1985 that might be exposed to significant moisture, and (4) eliminate the future use of UniShield cables at OCGS. The applicant tested 18 of its medium-voltage cable circuits in 2004 in a trial use of a new, state-of-the-art testing method based on partial discharge. As a result, one XLPE-insulated cable was replaced. The type of cable currently being used for inaccessible medium-voltage cable replacements is Okonite Okoguard, which is designed to water-resistant criteria. Additional medium-voltage cables are scheduled for testing. The applicant stated that the current inspection program will remain in effect until it is replaced by the Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program prior to entering the period of extended operation.

The applicant stated that 31 cables are currently located underground. Two unit substation (1A2 and 1B2) cables were rerouted and are at the top of the sand bed in the turbine building basement. Two cables, one for unit substation 1B1 and one for the B condensate pump, were rerouted above ground. Future reroutes of two other cables to aboveground locations are planned for refueling outage 1R21 in 2006. These two cables are for the 2C feedwater and C condensate pump motors.

Currently, OCGS implements a medium-voltage cable testing program for its 5 kV cables. The intent of the program is to identify the potential for cable failure and implement a replacement before failure. Testing has been completed for all 47 OCGS 2.3 kV and 4.1 kV cables. Of the 42 4.1 kV cables, 38 have been tested using a new test methodology by DTE that performs an online detection of partial discharge methodology. Eighteen were tested in 2004 and twenty were tested in 2005 using the DTE methodology. The remaining 2.3 kV and 4.1 kV cables have had their insulation integrity checked by step (from 1 kV to 10 kV) voltage testing. Additionally, the applicant has replaced approximately 75 percent of its original 5 kV cables. The project team noted that the existing cable testing program and extensive cable replacements demonstrate the applicant’s heightened attention to medium-voltage cable issues.

The project team also reviewed the operating experience provided in the OCGS LRA and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

The project team noted that OCGS AMP B.1.36 is a new program that includes the underground circuits in the 2.4 kV, 4.16 kV, 13.8 kV, and 34.5 kV systems at OCGS. This program will test in-scope medium-voltage cables at OCGS to provide an indication of the condition of the conductor insulation. The specific type of test performed will be an industry-endorsed, proven test for detecting deterioration of the insulation system resulting from wetting, such as power factor, partial discharge, or polarization index, as described in EPRI TR-103834-P1-2, or other testing that is state-of-the-art at the time the test is performed. Additionally, inspections for water collection in the manholes, conduits, and sumps containing medium-voltage cables within the scope of this program will be performed as a preventive measure. The applicant stated that underground circuits associated with the 13.8 kV circuits at the FRCT power plant, as well as 34.5 kV circuits that provide offsite feeds to OCGS, are included in the applicant's XI.E3 program. These circuits date back to the installation of alternate ac capabilities for station blackout (SBO) at OCGS in 1989. There have been no failures reported on these cables.

The project team asked the applicant whether it has any plans to trend the cable test data during the extended period of operation. The applicant stated that ongoing test results from the current OCGS medium-voltage cable testing program are being trended. Trending of test results will continue through the period of extended operation.

In its letter dated April 17, 2006 (ML061150320) and in its response to audit questions (ML060600122), the applicant committed to revise Appendix A Table A.05 commitment #36, and OCGS LRA Appendices A.1.36 and B.1.36, to state that cable test/monitoring frequency will be at least once every 10 years, that it will be adjusted based on test/monitoring results, and that the test results will be trended. **This is Audit Commitment 3.0.3.1.10-3**.

The project team also noted that the recent industry concern with dc high-potential testing and its impact on the life of cables is not a concern at OCGS because the majority of the medium-voltage cables at OCGS are tested using partial discharge and/or power factor testing methodologies. The applicant stated that it is not currently implementing the hi-pot testing at OCGS as part of its medium-voltage cable testing program except for five circuits feeding the 2.4 kV recirculation pump motors. These cables are dc step-voltage tested to only a maximum of 4 kV. The industry concern regards hi-pot testing at very high dc voltages.

The staff believes that the corrective action process will capture internal and external plant operating issues to ensure that aging effects are adequately managed.

On the basis of its review of the above plant-specific operating experience, as well as discussions with the applicant's technical staff, the project team determined that the applicant's Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.1.10.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program in Section A.1.36

of Appendix A to the OCGS LRA, which states that the Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is a new program that will be used to manage the aging of medium-voltage (2.3 kV, 4.1 kV, and 13.8 kV) cable circuits at OCGS. These cables may at times be exposed to moisture and may be subjected to system voltage for more than 25 percent of the time. Manholes, conduits, and sumps associated with these cable circuits will be inspected for water collection at least once every 2 years and drained as required. The first inspections will be completed before the period of extended operation. In addition, the cable circuits will be evaluated using a proven test for detecting deterioration of the insulation system resulting from wetting, such as power factor, partial discharge, or polarization index, as described in EPRI TR-103834-P1-2, or other testing that is state-of-the-art at the time the test is performed. The cable circuits will be tested at least once every 10 years. This new program will be implemented before the period of extended operation.

The applicant stated that the inclusion of the 13.8 kV system circuits in this program reflects the scope expansion of the SBO system electrical commodities and the 34.5 kV system cables as a result of its reconciliation of the September 2005 revision of NUREG-1801 to the January 2005 draft revision.

The project team also reviewed the license renewal commitment list in Section A.5 of the OCGS LRA to confirm that this program will be implemented before the period of extended operation, and noted that it is Item 36 on the list of commitments. In addition, the applicant stated that it will revise Commitment 36 to address new audit commitments 3.0.3.1.10-1, -2, and -3.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.36. Contingent upon the inclusion of commitments 3.0.3.1.10-1, 2, and 3, the project team found that it was consistent with the GALL Report, and determined that it provided an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.1.10.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that all the program elements are consistent with the GALL Report. On the basis of its review of the UFSAR Supplement for this program, contingent upon the inclusion of commitments 3.0.3.1.10-1, 2, and 3, the project team found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.11 Environmental Qualification Program (OCGS AMP B.3.2)

In OCGS LRA, Appendix B, Section B.3.2, the applicant stated that OCGS AMP B.3.2, ?Environmental Qualification (EQ) Program," is an existing plant program that is consistent with GALL AMP X.E1, ?Environmental Qualification (EQ) of Electrical Components."

3.0.3.1.11.1 Program Description

In the OCGS LRA, the applicant stated that this program is implemented through station procedures and preventive maintenance tasks. The OCGS EQ program complies with 10 CFR 50.49, ?Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants." All EQ equipment is included within the scope of license renewal. The program provides for maintenance during the qualified life of electrical equipment important to safety within the scope of 10 CFR 50.49. Program activities establish, demonstrate, and document the level of qualification, qualified configuration, maintenance, surveillance, and replacement requirements necessary to meet 10 CFR 50.49. Reanalysis addresses attributes of analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, corrective actions if acceptance criteria are not met, and the period of time before the end of qualified life when the reanalysis will be completed. Qualified life is determined for equipment within the scope of the EQ program, and appropriate actions such as replacement or refurbishment are taken before or at the end of the qualified life of the equipment so that the aging limit is not exceeded.

The applicant also stated that the EQ program addresses the low-voltage I&C cable issues, consistent with those described in the closure of Generic Safety Issue (GSI) 168, ?Environmental Qualification of Electrical Equipment."

3.0.3.1.11.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.3.2 is consistent with GALL AMP X.E1.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.3.2, including PBD-AMP-B.3.02, ?Environmental Qualification (EQ) Program," Revision 0, which assesses the AMP elements' consistency with GALL AMP X.E1. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.3.2 and associated bases documents to determine their consistency with GALL AMP X.E1.

The project team reviewed those portions of the applicant's EQ program for which the applicant claims consistency with GALL AMP X.E1 and found that they are consistent with this GALL AMP. On the basis of its review, the project team determined that the applicant's EQ program provided reasonable assurance that electrical components important to safety in harsh environments will be adequately managed. The project team found that the applicant's EQ program conforms to the recommended GALL AMP X.E1.

3.0.3.1.11.3 Exceptions to the GALL Report

None

3.0.3.1.11.4 Enhancements

None

3.0.3.1.11.5 Operating Experience

In the OCGS LRA, the applicant stated that the EQ program provides for consideration of operating experience to reconcile qualification bases and conclusions, including the equipment qualified life. Operating experience and system, equipment, or component-related information, as reported through NRC bulletins, notices, circulars, generic letters, and 10 CFR Part 21 notifications, are evaluated for applicability. The evaluations are documented and corrective actions are identified. Operating experience is reviewed to determine if it is applicable to EQ equipment. When the applicant has identified problems through industry or plant-specific experience, it has taken corrective actions to prevent recurrence.

The project team's review of the applicable correction action program database and sample EQ binders did not reveal any occurrence where the qualified life of a component has been exceeded. This review did not indicate any adverse trend in the EQ program.

The project team also reviewed the operating experience provided in the OCGS LRA and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant's EQ program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.1.11.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the EQ program in Section A.3.2 of Appendix A to the OCGS LRA, which states that the EQ program is an existing program that manages the aging of electrical equipment within the scope of 10 CFR 50.49. The program establishes, demonstrates, and documents the level of qualification, qualified configurations, maintenance, surveillance, and replacements necessary to meet 10 CFR 50.49. A qualified life is determined for equipment within the scope of the program, and appropriate actions such as replacement or refurbishment are taken before or at the end of the qualified life of the equipment so that the aging limit is not exceeded. The effects of aging on the intended functions will be adequately managed in accordance with the requirements of 10 CFR 54.21(c)(1)(iii). In Appendix A to the OCGS LRA, the applicant states that EQ components that cannot be qualified for 60 years will be replaced before the end of their qualified life (Commitment 45).

The project team reviewed the UFSAR Supplement for OCGS AMP B.3.2, found that it was consistent with the GALL Report, and determined that it provided an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.1.11.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those portions of the program for which the applicant claims consistency with the GALL Report are consistent with the GALL Report. On the basis of its review of the UFSAR Supplement for this program, the project team found that it provided an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2 OCGS AMPs That Are Consistent with the GALL Report with Exceptions and/or Enhancements

3.0.3.2.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, AND IWD (OCGS AMP (B.1.1)

In the OCGS LRA, Appendix B, Section B.1.1, the applicant stated that OCGS AMP B.1.1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," is an existing plant program that is consistent with GALL AMP XI.M1, with exceptions and an enhancement.

3.0.3.2.1.1 Program Description

In the OCGS LRA, the applicant stated that this program is part of its Inservice Inspection (ISI) program, and that it provides for condition monitoring of reactor coolant pressure retaining piping and components within the scope of license renewal. It also provides for condition monitoring of reactor internal components within the scope of license renewal, and the isolation condenser. The program is implemented through procedures that require examinations consistent with ASME Section XI, and through specific tasks that require the ASME Section XI augmentation activities identified in NUREG-1801. The program includes:

- Cracking monitoring for susceptible inservice inspection components subject to a steam or treated water environment, through volumetric examinations of pressure retaining welds and their heat affected zones in piping components.

- Cracking monitoring of the reactor vessel flange leak detection line.

- Cracking monitoring of the isolation condensers through surface and volumetric examinations of pressure retaining nozzle welds and their heat affected zones that are subject to a steam or reactor water environment.

- Loss of material monitoring of portions of the isolation condensers subject to a steam or reactor water environment, through system pressure tests.

- Cracking detection of the isolation condenser tube side components due to stress corrosion cracking and intergranular stress corrosion cracking, or loss of material detection due to general, pitting and crevice corrosion through temperature and radioactivity monitoring of the shell-side (cooling) water, eddy current inspections of the tubes, and inspections (VT or UT) of the channel head and tube sheets.

3.0.3.2.1.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.1 is consistent with GALL AMP XI.M1, with exceptions and an enhancement.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.1, including basis document PBD-AMP-B.1.01, ?ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," Revision 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M1. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.1 and associated bases documents to determine their consistency with GALL AMP XI.M1.

In reviewing this AMP, the project team noted that the program description in the OCGS LRA for AMP B.1.1 lists five aging effects for which this AMP will be credited to manage aging. However, in addition to the five aging effects listed, the OCGS LRA credits AMP B.1.1 for managing aging of CASS components subject to loss of fracture toughness due to thermal aging embrittlement (see Table 3.1.1, item 47). The project team asked the applicant to clarify why this aging effect is not included in the AMP listing, and to identify any other aging effects for which this AMP is credited in the LRA that are not included in the AMP listing.

In its response, the applicant stated that the list included in the OCGS LRA program description for AMP B.1.1 provides examples of the methods by which the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program addresses loss of material and cracking initiation and growth for which the program is credited to manage aging. No example was provided for loss of fracture toughness; however, it is also an aging effect for which the program is credited. Crack initiation and growth, loss of material, and loss of fracture toughness are the only aging effects for which this AMP is credited. The project team found the applicant's response acceptable since it clarifies that loss of fracture toughness is an aging effect for which this AMP is credited, which is consistent with the aging management reviews in the OCGS LRA.

The program description in the OCGS LRA for AMP B.1.1 also states that the program is implemented through procedures that require examinations consistent with ASME Section XI. The project team asked the applicant to describe the qualifications and training requirements for personnel that perform inspections and examinations under the ASME ISI program.

In its response, the applicant provided OCGS procedure TQ-AA-122, ?Qualification and Certification of Nondestructive Examination (NDE) Personnel," Rev. 1, which provides the OCGS qualification and training requirements for personnel performing inspections and examinations under the ASME ISI program. This procedure applies to all personnel certified to perform NDE inspections. The project team reviewed this procedure and determined that personnel certified in NDE are qualified in accordance with ASNT SNT-TC-1A, through 1984 Edition; ANSI/ASNT CP-189, 1991 edition; and ASME Section XI, 1986 through 1998 Edition, as applicable. Four levels of qualification are identified, including NDE Level I to III and NDE instructor. Education, training, and experience requirements are addressed for each level. The project team reviewed these training requirements and determined that they are acceptable to ensure that qualified personnel are used to perform the ASME inspections. In addition, the applicant provided a copy of OCGS procedure ER-AA-325-025, ?Oversight of Vendor NDE Activities," Rev. 1, which details the requirements for vendors. The project team reviewed this document and confirmed that appropriate qualification and training requirements are implemented for vendors that perform ASME Section XI, Subsection IWB, IWC, and IWD inspections.

The project team further noted that the program basis document for AMP B.1.1 (PBD-AMP-B.1.01) stated that repairs and replacements are performed in accordance with the 1995 ASME Section XI Code, 1996 addenda, which specifies the requirements in IWA-4000. The GALL Report refers to sections IWB-4000, IWC-4000, and IWD-4000 for repairs, and sections IWB-7000, IWC-7000, and IWD-7000 for replacements. In reviewing the ASME Section XI Code, the project team determined that Sections IWB-4000, IWC-4000, and IWD-4000 for repairs, and sections IWB-7000, IWC-7000, and IWD-7000 for replacements have been deleted in later versions of the ASME Section XI Code, including the 1995 version, and the requirements have been incorporated into Section IWA-4000. Therefore, the applicant has appropriately referenced section IWA-4000 for repairs and replacement in the program basis document for this program.

The project team reviewed those portions of the OCGS ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program for which the applicant claimed consistency with

GALL AMP AMP XI.M1 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program conforms to the recommended GALL AMP XI.M1, with the exceptions and enhancement described below.

3.0.3.2.1.3 Exceptions to the GALL Report

In the OCGS LRA, the applicant stated the following exceptions to the GALL Report program elements:

Exception 1

Elements:
1. Scope of Program
4. Detection of Aging Effects
5. Monitoring and Trending
6. Acceptance Criteria
7. Corrective Actions

Exception: NUREG-1801 indicates that the aging of the isolation condenser is to be managed by ASME Section XI Inservice Inspection (ISI) Subsection IWB (for Class 1 components). However, the Oyster Creek isolation condensers are ISI Class 2 on the tube side and ISI Class 3 on the shell side. Therefore, Subsections IWC and IWD are used, as Class 1 requirements do not apply.

The GALL Report identifies the following recommendations for the ?scope of program," ?detection of aging effects," ?monitoring and trending," ?acceptance criteria," and ?corrective actions" program elements associated with the exception taken:

1. *Scope of Program*: The ASME Section XI program provides the requirements for ISI, repair, and replacement. The components within the scope of the program are specified in Subsections IWB-1100, IWC-1100, and IWD-1100 for Class 1, 2, and 3 components, respectively, and include all pressure-retaining components and their integral attachments in light-water cooled power plants. The components described in Subsections IWB-1220, IWC-1220, and IWD-1220 are exempt from the examination requirements of Subsections IWB-2500, IWC-2500, and IWD-2500.

4. *Detection of Aging Effects*: The extent and schedule of the inspection and test techniques prescribed by the program are designed to maintain structural integrity and ensure that aging effects will be discovered and repaired before the loss of intended function of the component. Inspection can reveal cracking, loss of material due to corrosion, leakage of coolant and indications of degradation due to wear or stress relaxation, such as verification of clearances, settings, physical displacements, loose or missing parts, debris, wear, erosion, or loss of integrity at bolted or welded connections.

Components are examined and tested as specified in Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1, respectively, for Class 1, 2, and 3 components. The tables specify the extent and schedule of the inspection and examination methods for the components of the pressure-retaining boundaries. Alternative approved methods that meet the requirements of IWA-2240 are also specified in these tables.

5. *Monitoring and Trending*: For Class 1, 2, or 3 components, the inspection schedule of IWB-2400, IWC-2400, or IWD-2400, respectively, and the extent and frequency of IWB- 2500-1, IWC-2500-1, or IWD-2500-1, respectively, provides for timely detection of degradation. The sequence of component examinations established during the first inspection interval is repeated during each successive inspection interval, to the extent practical. If flaw conditions or relevant conditions of degradation are evaluated in accordance with IWB-3100, IWC-3100, or IWD-3100, and the component is qualified as acceptable for continued service, the areas containing such flaw indications and relevant conditions are reexamined during the next three inspection periods of IWB-2110 for Class 1 components, IWC-2410 for Class 2 components, and IWD-2410 for Class 3 components. Examinations that reveal indications that exceed the acceptance standards described below are extended to include additional examinations in accordance with IWB- 2430, IWC-2430, or IWD-2430 (1995 edition) for Class 1, 2, or, 3 components, respectively.

6. *Acceptance Criteria*: Any indication or relevant conditions of degradation detected are evaluated in accordance with IWB-3000, IWC-3000, or IWD-3000, for Class 1, 2, or 3 components, respectively. Examination results are evaluated in accordance with IWB-3100, IWC-3100, or IWD-3100 by comparing the results with the acceptance standards of IWB-3400 and IWB3500, or IWC-3400 and IWC-3500, or IWD3400 and IWD3500, respectively for Class 1 or Class 2 and 3 components. Flaws that exceed the size of allowable flaws, as defined in IWB-3500, IWC-3500, or IWD3500, are evaluated by using the analytical procedures of IWB-3600, IWC-3600, or IWD-3600, respectively, for Class 1 or Class 2, and 3 components. Flaws that exceed the size of allowable flaws, as defined in IWB-3500 or IWC-3500, are evaluated by using the analytical procedures of IWB-3600 or IWC-3600, respectively, for Class 1 or Class 2 and 3 components. Approved BWRVIP- 14, BWRVIP-59, and BWRVIP-60 documents provide guidelines for evaluation of crack growth in stainless steels, nickel alloys, and low-alloy steels, respectively.

7. *Corrective Actions*: For Class 1, 2, and 3, respectively, repair is performed in conformance with IWB-4000, IWC-4000, and IWD-4000, and replacement according to IWB-7000, IWC-7000, and IWD-7000. Approved BWRVIP-44 and BWRVIP-45 documents, respectively, provide guidelines for weld repair of nickel alloys and for weldability of irradiated structural components. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

In reviewing this exception, the project team noted that Table 3.2-1 in the OCGS UFSAR identifies the isolation condenser system as being Class 1. The project team asked the applicant to clarify and provide the technical basis for the current isolation condenser ISI classification.

In its response, the applicant stated that the isolation condensers are heat exchangers comprised of ISI Class 2 tube bundle assemblies inserted into ISI Class 3 shell assemblies. The condenser heat exchanger units do not contain any Class 1 components. OCGS UFSAR Table 3.2-1, which lists Class 1 systems, includes the isolation condenser system since the system contains ISI Class 1 piping and components from the attachment points on the reactor vessel to, and including, the containment isolation valves on both the steam supply side and the condensate return side. The piping changes to ISI Class 2 at the isolation valves and continues to the heat exchanger tube bundles as ISI Class 2. The Oyster Creek Inservice Inspection

Program Plan (OC-1) describing the ISI classifications of piping and components, including those of the isolation condenser system, is current licensing basis information. The ISI classification for the isolation condensers has not changed since originally determined, and was included in the submittal for each of the 10-year interval inspection programs to the NRC for review and evaluation.

To confirm the applicant's response, the project team reviewed the OCGS inservice inspection program plan (OC-1) titled ?OCGS ISI Program Plan Fourth Ten-Year Inspection Interval," Rev. 1, dated 09/30/04. Appendix B of that document, "Class 1 Systems Summary," page 2-53, confirms that the isolation condenser system has Class 1, 2 and 3 components. A transition from Class 1 to Class 2 occurs at isolation valves V-14-31, V-14-32, V-14-34, and V-14-35. Based upon the information in this document, the project team was able to verify that the isolation condenser tubes are Class 2 and the shell is Class 3, while piping connected directly to the reactor vessel is Class 1. This is part of the current licensing basis.

Since the isolation condenser tubes are Class 2, and the shell is Class 3 in the current licensing basis, the project team determined that the ASME Section XI ISI requirements for Class 1 components are not applicable to the isolation condenser. On this basis, the project team found this exception acceptable.

<u>Exception 2</u>

Elements:	Program Description 4. Detection of Aging Effects 5. Monitoring and Trending 6. Acceptance Criteria 7. Corrective Actions
Exception:	NUREG-1801 specifies the 2001 ASME Section XI B&PV Code, 2002 and 2003 Addenda for Subsections IWB, IWC, and IWD. The current Oyster Creek ISI Program Plan for the fourth ten-year inspection interval effective from October 15, 2002 through October 14, 2012, approved per 10CFR50.55a, is based on the 1995 ASME Section XI B&PV Code, 1996 addenda. The next 120-month inspection interval for Oyster Creek will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a 12 months before the start of the inspection interval.

The GALL Report identifies the following recommendations for the ?program description," ?detection of aging effects," ?monitoring and trending," ?acceptance criteria," and ?corrective actions" program elements associated with the exception taken:

> *Program Description*: Title 10 of the Code of Federal Regulations, 10 CFR 50.55a, imposes the inservice inspection (ISI) requirements of the ASME Code, Section XI, for Class 1, 2, and 3 pressure-retaining components and their integral attachments in light-water cooled power plants. Inspection, repair, and replacement of these components are covered in Subsections IWB, IWC, and IWD, respectively, in the 2001 edition[1] including the 2002 and 2003 Addenda. The program generally includes periodic visual, surface, and/or volumetric examination and leakage test of all Class 1, 2, and 3 pressure-retaining components and their integral attachments. The ASME Section XI

Inservice Inspection program in accordance with Subsections IWB, IWC, or IWD has been shown to be generally effective in managing aging effects in Class 1, 2, or 3 components and their integral attachments in light-water cooled power plants. However, in certain cases, the ASME inservice inspection program is to be augmented to manage effects of aging for license renewal and is so identified in the GALL Report.

[Footnote 1: An applicant may rely on a different version of the ASME Code, but should justify such use. An applicant may wish to refer to the SOC for an update of 10 CFR § 50.55a to justify use of a more recent edition of the Code.]

4. *Detection of Aging Effects*: The extent and schedule of the inspection and test techniques prescribed by the program are designed to maintain structural integrity and ensure that aging effects will be discovered and repaired before the loss of intended function of the component. Inspection can reveal cracking, loss of material due to corrosion, leakage of coolant and indications of degradation due to wear or stress relaxation, such as verification of clearances, settings, physical displacements, loose or missing parts, debris, wear, erosion, or loss of integrity at bolted or welded connections.

Components are examined and tested as specified in Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1, respectively, for Class 1, 2, and 3 components. The tables specify theextent and schedule of the inspection and examination methods for the components of the pressure-retaining boundaries. Alternative approved methods that meet the requirements of IWA-2240 are also specified in these tables.

5. *Monitoring and Trending*: For Class 1, 2, or 3 components, the inspection schedule of IWB-2400, IWC-2400, or IWD-2400, respectively, and the extent and frequency of IWB- 2500-1, IWC-2500-1, or IWD-2500-1, respectively, provides for timely detection of degradation. The sequence of component examinations established during the first inspection interval is repeated during each successive inspection interval, to the extent practical. If flaw conditions or relevant conditions of degradation are evaluated in accordance with IWB-3100, IWC-3100, or IWD-3100, and the component is qualified as acceptable for continued service, the areas containing such flaw indications and relevant conditions are reexamined during the next three inspection periods of IWB-2110 for Class 1 components, IWC-2410 for Class 2 components, and IWD-2410 for Class 3 components. Examinations that reveal indications that exceed the acceptance standards described below are extended to include additional examinations in accordance with IWB- 2430, IWC-2430, or IWD-2430 (1995 edition) for Class 1, 2, or, 3 components, respectively.

6. *Acceptance Criteria*: Any indication or relevant conditions of degradation detected are evaluated in accordance with IWB-3000, IWC-3000, or IWD-3000, for Class 1, 2, or 3 components, respectively. Examination results are evaluated in accordance with IWB-3100, IWC-3100, or IWD-3100 by comparing the results with the acceptance standards of IWB-3400 and IWB3500, or IWC-3400 and IWC-3500, or IWD3400 and IWD3500, respectively for Class 1 or Class 2 and 3 components. Flaws that exceed the size of allowable flaws, as defined in IWB-3500, IWC-3500, or IWD3500, are evaluated by using the analytical procedures of IWB-3600, IWC-3600, or IWD-3600, respectively, for Class 1 or Class 2, and 3 components. Flaws that exceed the size of allowable flaws, as defined in IWB-3500 or IWC-3500, are evaluated by using the analytical procedures of IWB-3600 or IWC-3600, respectively, for Class 1 or Class 2 and 3 components. Approved BWRVIP- 14, BWRVIP-59, and BWRVIP-60 documents provide guidelines for

evaluation of crack growth in stainless steels, nickel alloys, and low-alloy steels, respectively.

7. *Corrective Actions*: For Class 1, 2, and 3, respectively, repair is performed in conformance with IWB-4000, IWC-4000, and IWD-4000, and replacement according to IWB-7000, IWC-7000, and IWD-7000. Approved BWRVIP-44 and BWRVIP-45 documents, respectively, provide guidelines for weld repair of nickel alloys and for weldability of irradiated structural components. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

In reviewing this exception, the project team noted that, in accordance with Title 10 of the Code of Federal Regulations, Part 50, Section 55a (10 CFR 50.55a), the ASME code edition to be used for ISI inspections is the latest edition available 12 months prior to the start of the ten-year inspection interval. In the OCGS LRA, the applicant stated that Oyster Creek is currently in its fourth ten-year inspection interval, which is effective from October 15, 2002 through October 14, 2012. For this interval, the 1995 ASME Section XI Code, with 1996 addenda is the appropriate edition to be used; therefore, the project team determined that this exception is justified. On this basis, the project team found this exception acceptable.

3.0.3.2.1.4 Enhancements

In the OCGS LRA, the applicant identified the following enhancement in order to meet the GALL Report program elements:

Element(s): 1. Scope of Program
3. Parameters Monitored or Inspected
5. Monitoring and Trending

Enhancement: Enhancement activities, which are in addition to the requirements of ASME Section XI, Subsections IWB, IWC, and IWD, consist of temperature and radioactivity monitoring of the isolation condenser shell-side (cooling) water, eddy current testing of the tubes, and inspections (VT or UT) of the channel head and tube sheets, with verification of the effectiveness of the program through monitoring and trending of results.

Since the Oyster Creek isolation condenser tube bundles were replaced in the ?A” isolation condenser in 2000 and in the ?B” isolation condenser in 1998, utilizing upgraded materials that are more resistant to intergranular stress corrosion cracking, these inspections will be performed during the first ten years of the extended period of operation.

The GALL Report identifies the following recommendations for the ?scope of program,” ?parameters monitored or inspected,” and ?monitoring and trending” program elements associated with the stated enhancement:

1. *Scope of Program*: The ASME Section XI program provides the requirements for ISI, repair, and replacement. The components within the scope of the program are specified in Subsections IWB-1100, IWC-1100, and IWD-1100 for Class 1, 2, and 3 components,

respectively, and include all pressure-retaining components and their integral attachments in light-water cooled power plants. The components described in Subsections IWB-1220, IWC-1220, and IWD-1220 are exempt from the examination requirements of Subsections IWB-2500, IWC-2500, and IWD-2500.

3. *Parameters Monitored or Inspected*: The ASME Section XI ISI program detects degradation of components by using the examination and inspection requirements specified in ASME Section XI Tables IWB-2500-1, IWC-2500-1, or IWD-2500-1, respectively, for Class 1, 2, or 3 components.

5.*Monitoring and Trending*: For Class 1, 2, or 3 components, the inspection schedule of IWB-2400, IWC-2400, or IWD-2400, respectively, and the extent and frequency of IWB-2500-1, IWC-2500-1, or IWD-2500-1, respectively, provides for timely detection of degradation. The sequence of component examinations established during the first inspection interval is repeated during each successive inspection interval, to the extent practical. If flaw conditions or relevant conditions of degradation are evaluated in accordance with IWB-3100, IWC-3100, or IWD-3100, and the component is qualified as acceptable for continued service, the areas containing such flaw indications and relevant conditions are reexamined during the next three inspection periods of IWB-2110 for Class 1 components, IWC-2410 for Class 2 components, and IWD-2410 for Class 3 components. Examinations that reveal indications that exceed the acceptance standards described below are extended to include additional examinations in accordance with IWB- 2430, IWC-2430, or IWD-2430 (1995 edition) for Class 1, 2, or, 3 components, respectively.

In reviewing this enhancement, the project team noted that the OCGS program basis document for this AMP (PBD-AMP-B.1.01) includes the above enhancement in Section 2.4 ?Summary of Enhancements to NUREG-1801," however, the enhancement is not addressed in any of the 10 program elements evaluated in Section 3 ?Evaluation and Technical Basis." The applicant was asked to identify the specific program elements to which this enhancement applies.

The applicant stated that the program basis document, PBD-AMP-B.1.01, for the ASME Section XI Inservice Inspections, Subsections IWB, IWC, IWD will be revised to list the enhancement to add temperature and radioactivity monitoring of the isolation condenser shell-side (cooling) water, and eddy current testing of the tubes, and inspections (VT or UT) of the channel head and tube sheets, in program elements 1. scope of program, 3. parameters monitored or inspected, and 5. monitoring and trending.

The project team concurred with the program elements identified by the applicant as being impacted by this enhancement.

The project team also noted that Table IV.C1 in the GALL Report, item IV.C1-4 for isolation condenser components stated that GALL AMP XI.M1 is to be augmented to detect cracking due to stress corrosion cracking. In addition, the GALL Report stated that verification of the program's effectiveness is necessary to ensure that significant degradation is not occurring, and the component's intended function will be maintained during the extended period of operation. An acceptable verification program is to include temperature and radioactivity monitoring of the shell side water, and eddy current testing of the tubes. Therefore, the applicant's enhancement to add temperature and radioactivity monitoring of the isolation condenser shell-side (cooling) water, eddy current testing of the tubes, and inspections (VT or UT) of the channel head and tube sheets, with verification of the effectiveness of the program through monitoring and trending of results, will make the applicant's AMP consistent with the recommendations in the GALL Report AMP. On this basis, the project team found this enhancement acceptable.

The applicant was asked to clarify if the above enhancement activities will be included as part of OCGS AMP B.1.1, or if they will be included in a separate aging management program. In its response, the applicant stated that the enhancements for isolation condenser inspection will be included as part of the ASME Section XI ISI, Subsections IWB, IWC and IWD program. Inspections of the tube sheet and channel head will be performed as part of the maintenance activities required for performance of the eddy current examinations of the isolation condenser tubes, which is included as part of the B.1.1 program. The project team found this approach to be acceptable since the activities will be included in an existing aging management program.

On this basis, the project team found this enhancement acceptable since when the enhancement is implemented, OCGS AMP B.1.1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," will be consistent with GALL AMP XI.M1 and will provide additional assurance that the effects of aging will be adequately managed.

Considering the relatively short time period remaining before OCGS enters the license renewal period, the project team inquired about the status of implementing procedures required for new AMPs, and for significant enhancements to existing AMPs. The applicant was asked to provide (a) the status of the implementing procedures for each enhancement to the existing ASME Section XI ISI, Subsection IWB, IWC, and IWD program, (b) the schedule for initiating each of the enhancements to the existing ASME Section XI ISI, Subsection IWB, IWC, and IWD program, (c) a sample of an implementing procedure for one enhancement to the existing ASME Section XI ISI, Subsection IWB, IWC, and IWD program, and (d) the results of any enhanced inspections that have already been completed.

In its response, the applicant stated that implementing procedures for enhancements to OCGS AMP B.1.1 have been identified, and several are under development and in draft form; however, none were complete at the time of this audit. In addition, the applicant stated that the enhancement of eddy current testing of the isolation condenser tubes, with examination (VT or UT) of the tubesheet and shell head is to be performed during the first ten years of the period of extended operation. Shell water is currently periodically monitored for temperature and radioactivity, and procedure commitments addressing these enhancement activities will be in place prior to the period of extended operation. No enhanced inspections have been performed as of the time of this audit; consequently, no inspection results were available for review by the project team.

The project team reviewed the applicant's response and determined that it is acceptable since all activities will be completed prior to entering the period of extended operation.

3.0.3.2.1.5 Operating Experience

In the OCGS LRA, the applicant stated that Oyster Creek has successfully identified indications of age-related degradation prior to the loss of the intended functions of the components, and has taken appropriate corrective actions through evaluation, repair or replacement of the components in accordance with ASME Section XI and station implementing procedures. Some site-specific examples were provided. In addition, the applicant stated that periodic self assessments of the ISI programs have been performed to identify the areas that need improvement to maintain program quality.

In addition to reviewing the operating experience described in the OCGS LRA and program basis documents, the project team reviewed a self-assessment report titled ?Focused Area Self-Assessment (FASA) Report Oyster Creek ISI Program," which was performed April 26-29, 2004. The report confirms that self assessments have been performed to identify program strengths and weaknesses, as well as corrective actions needed. The report addresses the following areas: a) the repair and replacement program, b) the ISI, including IGSCC, program, c) the pressure test program, d) the snubber program, and e) the containment program (CISI). The report results related to the OCGS ISI program included the identification of 3 deficiencies and 12 recommendations for improvement. The deficiencies identified are the following:

- The use of ASME Code cases N-416-2,N-513-1, and –546 were approved by NRC, but were not included in the program document (OC-1)

- Augmented inspection requirements were not addressed in detail for NUREG-0619 BWR feedwater nozzle and CRD return line nozzle cracking; Branch Technical position MEB 3-1, "High Energy Fluid Systems, Protection Against Postulated Piping Failures in Fluid Systems Outside Containment;" a discussion of the Class 2 Thin Wall piping augmented inspections; and snubber visual inspection and testing performed in accordance with OCGS Technical Specifications Sections 3.5.A.8 and 4.5.M

- Relief Request OC-02-02 for the reactor pressure vessel support skirt knuckle weld received provisional approval from the NRC however, the provision to augment the ASME Code required surface examination with a volumetric (UT) examination of the restricted area is not addressed

A corrective action plan was issued to address all deficiencies identified in this report. The project team reviewed the deficiencies associated with the ISI program and determined that they did not adversely impact the conclusion that the OCGS AMP will effectively manage aging degradation.

The project team reviewed the operating experience provided in the OCGS LRA and in the AMP basis document, interviewed the applicant's technical staff, and confirmed that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience, and discussions with the applicant's technical staff, the project team determined that the applicant's ASME Section XI Inservice Inspection, Subsection IWB, IWC and IWD Program will adequately manage the aging effects for which this AMP is credited in the OCGS LRA.

3.0.3.2.1.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for this AMP in the OCGS LRA, Appendix A, Section A.1.1, which states that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program is an existing plant program that consists of periodic volumetric and visual examinations of components for assessment, identification of signs of degradation, and establishment of corrective actions. The inspections will be implemented in accordance with 10 CFR 50.55(a).

For the isolation condensers this program also includes enhancement activities identified in NUREG-1801, lines IV.C1-5 and IV.C1-6. These are new activities in addition to those required by ASME Section XI, Subsections IWB, IWC, and IWD. The isolation condenser test and inspection enhancement activities detect cracking due to stress corrosion cracking or intergranular stress corrosion cracking, and detect loss of material due to general, pitting and crevice corrosion. These enhancement activities verify that significant degradation is not occurring, and therefore that the intended function of the isolation condenser is maintained during the period of extended operation. These enhancement activities consist of temperature and radioactivity monitoring of the shell side water, which will be implemented prior to the period of extended operation, and eddy current testing of the tubes, with inspection (VT or UT) of the tubesheet and channel head, which will be performed during the first ten years of the period of extended operation.

The project team also reviewed the applicant's license renewal commitment list in Appendix A of the OCGS LRA, and confirmed that the enhancements to this program are identified and will be implemented prior to the period of extended operation as item 1 of the commitments.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.1, and found that it was consistent with the GALL Report. The project team determined that it provides an adequate summary description of the program, as identified in the SRP-LR UFSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.2.1.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report are consistent with the GALL Report. In addition, the project team reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. Also, the project team reviewed the enhancement and determined that implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The project team also reviewed the UFSAR Supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.2 Water Chemistry (OCGS AMP B.1.2)

In the OCGS LRA, Appendix B, Section B.1.2, the applicant stated that OCGS AMP B.1.2, ?Water Chemistry," is an existing plant program that is consistent with GALL AMP XI.M2, ?Water Chemistry," with exceptions.

3.0.3.2.2.1 Program Description

In the OCGS LRA, the applicant stated that this program's activities consist of measures that are used to manage aging of piping, piping components, piping elements and heat exchangers exposed to reactor water, condensate and feedwater, control rod drive water, demineralized water storage tank water (DWST), condensate storage tank water (CST), torus water, and spent fuel pool water. Reactor water, condensate, control rod drive, feedwater, demineralized water storage tank, condensate tank, torus and spent fuel pool water are classified as treated water for aging management. The program activities provide for monitoring and controlling of water chemistry using station procedures and processes based on BWRVIP-130: ?BWR Vessel and Internals Project BWR Water Chemistry Guidelines," 2004 Revision for the prevention or mitigation of loss of material, reduction of heat transfer and cracking aging effects. The Water Chemistry Program is also credited for mitigating loss of material and cracking for components exposed to sodium pentaborate and boiler treated water environments. The standby liquid control system contains a treated water and sodium pentaborate solution and is controlled in accordance with plant procedures and Technical Specifications. The heating and process steam system contains boiler treated water that is controlled in accordance with plant procedures.

In accordance with NUREG-1801, the applicant also stated that the Water Chemistry Program may not be effective in low flow or stagnant flow areas. The one-time inspection (B.1.24) aging management program includes provisions specified by NUREG-1801 for verification of chemistry control and confirmation of the absence of loss of material and cracking in stagnant flow areas in piping systems and components.

3.0.3.2.2.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.2 is consistent with GALL AMP XI.M2, with exceptions.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.2, including the OCGS Program basis document, PBD-AMP-B.1.02, ?Water Chemistry,” Rev. 0, dated 11-22-2005, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M2. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.2 and associated bases documents to determine their consistency with GALL AMP XI.M2.

Also, the project team reviewed several OCGS implementing procedures, including CY-AB-120-1100, ?Reactor Water Hydrogen Water Chemistry, Noble Chem and Zinc Injection,” Rev. 2 and CY-AB-120-100, ?Reactor Water Chemistry,” Rev. 7.

The applicant stated that OCGS started hydrogen water chemistry (HWC) in 1990, zinc injection in 2000 and noble metal chemical application (NMCA) in 2002. To implement these changes, the applicant has been following the most current update of the EPRI guidelines, which is currently BWRVIP-130, as applicable to the plant-specific needs to mitigate IGSCC in components exposed to reactor or treated water.

For HWC plants such as OCGS, BWRVIP-62, ?Technical Basis for Inspection Relief for BWR Internal Components with Hydrogen Injection,” and BWRVIP-75, ?Technical Basis for Revisions to GL 88-01 Inspection Schedules,” identify circumstances and conditions for which relief (to perform alternate inservice inspection activities in lieu of the current ISI commitments) may be granted by the staff. The applicant was asked if a request for relief has been submitted and approved because of the HWC status. In response, the applicant stated that OCGS has not yet submitted any relief requests to the staff based on its HWC status. The project team determined that the applicant’s response was acceptable since a relief request is not being relied upon to perform alternate inservice inspection activities in lieu of the current ISI commitments for the extended period of operation.

The project team recognized that flow accelerated corrosion (FAC) in carbon and low alloy steel components is affected by the alloy composition, the pH at operating conditions, dissolved oxygen concentration, fluid bulk velocity, component geometry and upstream influences, fluid temperature and steam quality. The oxygen affects the form and solubility of the oxide layer, the dissolution of which is inherent in FAC. Section 3.4 of BWRVIP-79 states that the rate of FAC increases dramatically if oxygen concentration is less than about 25 ppb in the feedwater and condensate system, therefore, oxygen is sometimes injected to achieve this oxygen level.

The applicant was asked to describe the OCGS procedures to maintain appropriate oxygen levels in reactor water in various plant primary and secondary systems, including main steam, feedwater and condensate, to mitigate loss of material due to FAC (i.e., erosion/corrosion, steam cutting, etc.). In response, the applicant provided a copy of OCGS implementing procedure CY-AB-120-110, ?Condensate and Feedwater Chemistry," Rev. 7. The project team reviewed this procedure and verified that the oxygen levels for the condensate and feedwater systems are monitored continuously to maintain them at a goal of 30-80 ppb. The oxygen levels for the main steam system are not specifically monitored. Typical reactor water oxygen levels with low HWC/NMCA plants (including OCGS) have often been in the region of 30 to 80 ppb. Since steam is generated from reactor water, for which oxygen level is monitored and controlled in accordance with implementing procedure CY-AB-120-100, Rev. 2, the oxygen level in the steam is maintained above 25 ppb. The project team found the applicant's procedures for controlling oxygen levels acceptable since they are consistent with the recommendations in BWRVIP-79.

The project team noted that Section 4 of BWRVIP-79 recommends that the reactor water iron level be monitored as a new diagnostic parameter, and the feedwater copper level be monitored as one of the control parameters. The project team asked the applicant to confirm that the OCGS Water Chemistry Program includes monitoring of these parameters, as stated in the BWRVIP-79 guidelines. In response, the applicant provided copies of OCGS implementing procedures CY-AB-120-100 (Rev. 2) and CY-AB-120-110 (Rev. 7). The project team reviewed these procedures, and verified that these parameters are appropriately monitored, as recommended in BWRVIP-130. Therefore, the project team found this acceptable.

The project team reviewed those portions of the Water Chemistry Program for which the applicant claims consistency with GALL AMP XI.M2 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's Water Chemistry Program conforms to the recommended GALL AMP XI.M2, with the exceptions described below.

3.0.3.2.2.3 Exceptions to the GALL Report

In the OCGS LRA, the applicant stated the following exceptions to the GALL Report program elements:

Exception 1

Elements: 1. Scope of Program
3. Parameters Monitored or Inspected

Exception: NUREG-1801 indicates that water chemistry control is in accordance with BWRVIP-29 for water chemistry in BWRs. BWRVIP-29 references the 1996 revision of EPRI TR-103515, "BWR Water Chemistry Guidelines." The Oyster Creek Water Chemistry Program is based on BWRVIP-130, which is the 2004 Revision of "BWR Water Chemistry Guidelines." EPRI periodically updates the water chemistry guidelines, as new information becomes available.

The GALL Report identified the following recommendations for the ?scope of program" and ?parameters monitored or inspected" program elements associated with the exception taken:

> *1. Scope of Program:* The program includes periodic monitoring and control of known detrimental contaminants such as chlorides, fluorides (PWRs only), dissolved oxygen, and sulfate concentrations below the levels known to result in loss of material or cracking. Water chemistry control is in accordance with industry guidelines such as BWRVIP-29 (EPRI TR-103515) for water chemistry in BWRs, EPRI TR-105714 for primary water chemistry in PWRs, and EPRI TR-102134 for secondary water chemistry in PWRs.
>
> *3. Parameters Monitored or Inspected:* The concentration of corrosive impurities listed in the EPRI guidelines discussed above, which include chlorides, fluorides (PWRs only), sulfates, dissolved oxygen, and hydrogen peroxide, are monitored to mitigate degradation of structural materials. Water quality (pH and conductivity) is also maintained in accordance with the guidance. Chemical species and water quality are monitored by in process methods or through sampling. The chemical integrity of the samples is maintained and verified to ensure that the method of sampling and storage will not cause a change in the concentration of the chemical species in the samples.
>
> *BWR Water Chemistry:* The guidelines in BWRVIP-29 (EPRI TR-103515) for BWR reactor water recommend that the concentration of chlorides, sulfates, and dissolved oxygen are monitored and kept below the recommended levels to mitigate corrosion. The two impurities,chlorides and sulfates, determine the coolant conductivity; dissolved oxygen, hydrogen peroxide, and hydrogen determine electrochemical potential (ECP). The EPRI guidelines recommend that the coolant conductivity and ECP are also monitored and kept below the recommended levels to mitigate SCC and corrosion in BWR plants. The EPRI guidelines in BWRVIP-29 (TR-103515) for BWR feedwater, condensate, and control rod drive water recommend that conductivity, dissolved oxygen level, and concentrations of iron and copper (feedwater only) are monitored and kept below the recommended levels to mitigate SCC. The EPRI guidelines in BWRVIP-29 (TR-103515) also include recommendations for controlling water chemistry in auxiliary systems: torus/pressure suppression chamber, condensate storage tank, and spent fuel pool.

In the OCGS LRA, the applicant stated that the OCGS water chemistry AMP is based on BWRVIP-130 (EPRI-TR-1008192): ?BWR Vessel and Internals Project BWR Water Chemistry Guidelines – 2004 Revision," which is the latest revision of the EPRI water chemistry guidelines for BWR plants. The GALL Report recommends BWRVIP-29 (which is Revision 1 of the EPRI document EPRI-TR-103515, published in 1996), or later revisions.

The project team recognized that the staff's SER for the peach Bottom and Dresden/Quad Cities LRA (NUREGs-1769 and 1796) has accepted BWRVIP-79, which is Revision 2 of the EPRI document EPRI-TR-103515, published in 2000. Therefore, the project team reviewed the applicant's assessment of the differences between the 2000 revision (BWRVIP-79) and 2004 revision (BWRVIP-130), which are provided in the applicant's response to an audit question. The comparison demonstrated that the use of the 2004 revision of the EPRI BWR water chemistry guidelines provides an acceptable method of controlling water chemistry that is consistent with the GALL recommendations. On this basis, the project team found this exception acceptable.

Exception 2

Elements:	1. Scope of Program 3. Parameters Monitored or Inspected
Exception:	In transitioning from TR-103515-R2 to BWRVIP-130, Oyster Creek has reviewed BWRVIP-130 and has determined that the most significant difference from Revision 2 is that a recent policy of the U.S. nuclear industry commits each nuclear utility to adopting the responsibilities and processes on the management of materials aging issues described in ?NEI 03-08: Guideline for the Management of Materials Issues." Section 1 of the BWR Water Chemistry Guidelines specifies which portions of the document are ?Mandatory," ?Needed," or ?Good Practices," using the classification described in NEI 03-08. A new section (section 7) has been added and contains recommended goals for water chemistry optimization. These are ?good practice" recommendations for targets that plants may use in optimizing water chemistry that balances the conflicting requirements of materials, fuel and radiation control. Significant time and expense may be required to meet these targets; thus efforts to achieve these goals should be considered in the context of the overall strategic plan for the plant. Therefore, Oyster Creek is not committing to obtaining these targets. All other changes do not change the original intent of revision 2 implementation.

The GALL Report identified the following recommendations for the ?scope of program" and ?parameters monitored or inspected" program elements associated with the exception taken:

1. Scope of Program: The program includes periodic monitoring and control of known detrimental contaminants such as chlorides, fluorides (PWRs only), dissolved oxygen, and sulfate concentrations below the levels known to result in loss of material or cracking. Water chemistry control is in accordance with industry guidelines such as BWRVIP-29 (EPRI TR-103515) for water chemistry in BWRs, EPRI TR-105714 for primary water chemistry in PWRs, and EPRI TR-102134 for secondary water chemistry in PWRs.

3. Parameters Monitored or Inspected: The concentration of corrosive impurities listed in the EPRI guidelines discussed above, which include chlorides, fluorides (PWRs only), sulfates, dissolved oxygen, and hydrogen peroxide, are monitored to mitigate degradation of structural materials. Water quality (pH and conductivity) is also maintained in accordance with the guidance. Chemical species and water quality are monitored by in process methods or through sampling. The chemical integrity of the samples is maintained and verified to ensure that the method of sampling and storage will not cause a change in the concentration of the chemical species in the samples.

BWR Water Chemistry: The guidelines in BWRVIP-29 (EPRI TR-103515) for BWR reactor water recommend that the concentration of chlorides, sulfates, and dissolved oxygen are monitored and kept below the recommended levels to mitigate corrosion. The two impurities, chlorides and sulfates, determine the coolant conductivity; dissolved oxygen, hydrogen peroxide, and hydrogen determine electrochemical potential (ECP).

> The EPRI guidelines recommend that the coolant conductivity and ECP are also monitored and kept below the recommended levels to mitigate SCC and corrosion in BWR plants. The EPRI guidelines in BWRVIP-29 (TR-103515) for BWR feedwater, condensate, and control rod drive water recommend that conductivity, dissolved oxygen level, and concentrations of iron and copper (feedwater only) are monitored and kept below the recommended levels to mitigate SCC. The EPRI guidelines in BWRVIP-29 (TR-103515) also include recommendations for controlling water chemistry in auxiliary systems: torus/pressure suppression chamber, condensate storage tank, and spent fuel pool.

During the audit, the project team reviewed the water chemistry guidelines given in both BWRVIP-79 (EPRI TR-103515-R2) and BWRVIP-130 (EPRI TR-1008192) and noted that the new section 7 in BWRVIP-130 contains goals for water chemistry optimization. These are ?good practice" recommended targets that plants may use in optimizing water chemistry in order to balance the conflicting requirements of materials, fuel and radiation control. The project team also noted that all other changes between BWRVIP-79 and BWRVIP-130 do not change the original intent of the Revision 2 guidelines in BWRVIP-79. The applicant was asked to clarify the details of this exception since it was not clear why this exception was needed. Based on the applicant's response, the project team determined that not all of the good practices recommended in BWRVIP-130 are applicable to, or achievable by OCGS. However, the applicant has implemented those practices that are applicable to the plant and are beneficial to the total water chemistry optimization program. For example, an excess of feedwater zinc can be harmful to reactor fuel, but beneficial for radiation field control. At OCGS, the applicant establishes an optimum zinc program to protect the fuel, as well as manage radiation control.

The project team determined that the applicant has implemented those good practice recommendations that are applicable to the conditions of the OCGS reactor water, and beneficial to the total water chemistry optimization program. On this basis, the project team found this exception acceptable.

<u>Exception 3</u>

Elements:
1. Scope of Program
3. Parameters Monitored or Inspected

Exception: NUREG-1801 indicates that hydrogen peroxide is monitored to mitigate degradation of structural materials. The Oyster Creek program does not monitor for hydrogen peroxide because the rapid decomposition of hydrogen peroxide makes reliable data exceptionally difficult to obtain and BWRVIP-130 Section 6.3.3, "Water Chemistry Guidelines for Power Operation," does not address monitoring for hydrogen peroxide. Hydrogen addition to feedwater has been applied in order to mitigate occurrence of IGSCC of structural materials by suppressing the formation of hydrogen peroxide. The hydrogen addition has accomplished an Electrochemical Corrosion Potential (ECP) value less than -230mV, SHE (Standard Hydrogen Electrode). By maintaining a low ECP less than -230mV, SHE, the reactor water chemistry minimizes the effects from hydrogen peroxide below the threshold that prompted the issue raised in NUREG 1801. Oyster Creek uses the ISI program to investigate whether structural degradation in potentially affected locations is ongoing. Oyster Creek's ISI program provides for condition monitoring of the reactor vessel, reactor internal components and ASME Class 1 pressure retaining components in accordance with ASME Section XI, Subsection IWB. Indications and relevant conditions detected during examinations are evaluated in accordance with ASME Section XI Articles IWB-3000, for Class 1.

The GALL Report identified the following recommendations for the ?scope of program" and ?parameters monitored or inspected" program element associated with the exception taken:

> *1. Scope of Program:* The program includes periodic monitoring and control of known detrimental contaminants such as chlorides, fluorides (PWRs only), dissolved oxygen, and sulfate concentrations below the levels known to result in loss of material or cracking. Water chemistry control is in accordance with industry guidelines such as BWRVIP-29 (EPRI TR-103515) for water chemistry in BWRs, EPRI TR-105714 for primary water chemistry in PWRs, and EPRI TR-102134 for secondary water chemistry in PWRs.
>
> *3. Parameters Monitored or Inspected:* The concentration of corrosive impurities listed in the EPRI guidelines discussed above, which include chlorides, fluorides (PWRs only), sulfates, dissolved oxygen, and hydrogen peroxide, are monitored to mitigate degradation of structural materials. Water quality (pH and conductivity) is also maintained in accordance with the guidance. Chemical species and water quality are monitored by in process methods or through sampling. The chemical integrity of the samples is maintained and verified to ensure that the method of sampling and storage will not cause a change in the concentration of the chemical species in the samples.
>
> *BWR Water Chemistry:* The guidelines in BWRVIP-29 (EPRI TR-103515) for BWR reactor water recommend that the concentration of chlorides, sulfates, and dissolved oxygen are monitored and kept below the recommended levels to mitigate corrosion. The two impurities, chlorides and sulfates, determine the coolant conductivity; dissolved oxygen, hydrogen peroxide, and hydrogen determine electrochemical potential (ECP). The EPRI guidelines recommend that the coolant conductivity and ECP are also monitored and kept below the recommended levels to mitigate SCC and corrosion in BWR plants. The EPRI guidelines in BWRVIP-29 (TR-103515) for BWR feedwater, condensate, and control rod drive water recommend that conductivity, dissolved oxygen level, and concentrations of iron and copper (feedwater only) are monitored and kept below the recommended levels to mitigate SCC. The EPRI guidelines in BWRVIP-29 (TR-103515) also include recommendations for controlling water chemistry in auxiliary systems: torus/pressure suppression chamber, condensate storage tank, and spent fuel pool.

As part of the audit, the project team interviewed the applicant's technical staff to discuss technical issues related to this exception. During the interview, the applicant stated that hydrogen addition to feedwater has been applied to mitigate occurrence of IGSCC in structural materials by suppressing the formation of hydrogen peroxide. The hydrogen addition has accomplished an Electrochemical Corrosion Potential (ECP) value less than -230mV, SHE (Standard Hydrogen Electrode). By maintaining a low ECP less than -230mV, SHE, the reactor water chemistry minimizes the effects from hydrogen peroxide.

The project team recognized that the ECP quantifies the oxidizing power of a solution in contact with a specific metal surface. The ECP of different reactor internals component materials is very sensitive to the concentration of oxygen, hydrogen, and hydrogen peroxide (which determine the ECP), and therefore is different at different locations within the BWR reactor system. Section 5.3 of BWRVIP-79 discusses the potential locations suitable for measuring the ECP (Fig. 5.5) and Section 5.4 provides alternate ECP estimation techniques. Therefore, the applicant was asked to clarify how the threshold ECP level is maintained within the reactor system without monitoring the hydrogen peroxide level.

In its response, the applicant stated that at OCGS the ECP is directly monitored with ECP probes in the B recirculation loop via the reactor water cleanup (RWCU) system (location E in Fig. 5.5 of BWRVIP-79). In addition, the dissolved oxygen is monitored in the reactor water as a secondary parameter to ensure that mitigation is maintained in the recirculation loops. To assure that an adequate excess of hydrogen relative to oxygen is present to reduce the ECP below -230 mV (SHE) at target locations during power operation, the measured reactor water hydrogen-to-oxygen molar ratio (an alternate to ECP per Appendix E of BWRVIP-130) is maintained at greater than 3 during hydrogen injection. Thus, OCGS has chosen a strategy that uses ECP or the measured molar ratio of hydrogen-to-oxygen as the primary indicator of IGSCC mitigation with proof of sufficient catalyst loading. According to OCGS implementing procedure CY-AB-120-1000 (Rev. 2), Section 4.6B, verification of mitigation can also be based on radiolysis modeling using an EPRI model as an alternate to ECP measurement.

The project team determined that the OCGS Water Chemistry Program includes activities that are adequate to ensure that the reactor water contains an adequate excess of hydrogen relative to oxygen to reduce the ECP below -230 mv (SHE) at target locations. On this basis, the project team found this exception acceptable.

<u>Exception 4</u>

Elements:	1. Scope of Program 3. Parameters Monitored or Inspected
Exception:	NUREG-1801 indicates that dissolved oxygen is monitored. Consistent with the guidance provided in BWRVIP-130, condensate storage tank, demineralized water storage tank water, spent fuel pool water and torus water are not sampled for dissolved oxygen. The Oyster Creek chemistry procedures require monitoring of conductivity, chlorides, sulfates and total organic carbon (TOC) in accordance with limits set by BWRVIP-130 as an alternate method for ensuring component integrity.

The GALL Report identified the following recommendations for the ?scope of program” and ?parameters Monitored or Inspected” program elements associated with the exception taken:

> *1. Scope of Program:* The program includes periodic monitoring and control of known detrimental contaminants such as chlorides, fluorides (PWRs only), dissolved oxygen, and sulfate concentrations below the levels known to result in loss of material or cracking. Water chemistry control is in accordance with industry guidelines such as BWRVIP-29 (EPRI TR-103515) for water chemistry in BWRs, EPRI TR-105714 for

primary water chemistry in PWRs, and EPRI TR-102134 for secondary water chemistry in PWRs.

3. Parameters Monitored or Inspected: The concentration of corrosive impurities listed in the EPRI guidelines discussed above, which include chlorides, fluorides (PWRs only), sulfates, dissolved oxygen, and hydrogen peroxide, are monitored to mitigate degradation of structural materials. Water quality (pH and conductivity) is also maintained in accordance with the guidance. Chemical species and water quality are monitored by in process methods or through sampling. The chemical integrity of the samples is maintained and verified to ensure that the method of sampling and storage will not cause a change in the concentration of the chemical species in the samples.

BWR Water Chemistry: The guidelines in BWRVIP-29 (EPRI TR-103515) for BWR reactor water recommend that the concentration of chlorides, sulfates, and dissolved oxygen are monitored and kept below the recommended levels to mitigate corrosion. The two impurities, chlorides and sulfates, determine the coolant conductivity; dissolved oxygen, hydrogen peroxide, and hydrogen determine electrochemical potential (ECP). The EPRI guidelines recommend that the coolant conductivity and ECP are also monitored and kept below the recommended levels to mitigate SCC and corrosion in BWR plants. The EPRI guidelines in BWRVIP-29 (TR-103515) for BWR feedwater, condensate, and control rod drive water recommend that conductivity, dissolved oxygen level, and concentrations of iron and copper (feedwater only) are monitored and kept below the recommended levels to mitigate SCC. The EPRI guidelines in BWRVIP-29 (TR-103515) also include recommendations for controlling water chemistry in auxiliary systems: torus/pressure suppression chamber, condensate storage tank, and spent fuel pool.

As part of the audit, the applicant's technical staff were interviewed to discuss technical issues related to this exception. During the interview, the applicant stated that the water in the condensate storage tank, demineralized water storage tank, spent fuel pool, and torus are exposed to atmospheric conditions (i.e., air-saturated) and hence, measuring dissolved oxygen in the water for these locations would not provide the actual oxygen content nor help determine the quality of the water. The applicant was asked to explain what alternate parameters are monitored for the water in these tanks, which are exposed to the atmosphere and therefore contain water saturated with oxygen. In its response, the applicant stated that dissolved oxygen is monitored routinely for the feedwater, condensate and CRD water systems, as recommended in BWRVIP-130, and thus, is consistent with GALL. However, the above tanks or reservoirs associated with these systems are monitored for conductivity, chlorides, sulfates and total organic carbon (TOC) in accordance with limits set by BWRVIP-130, Appendix B, as an alternate method for ensuring component integrity.

The project team determined that the OCGS Water Chemistry Program monitors the water both within the subject systems, and within their associated tanks or reservoirs, as recommended in BWRVIP-130. On this basis, the project team found this exception acceptable.

Exception 5

Elements: 1. Scope of Program
3. Parameters Monitored or Inspected

Exception: NUREG-1801 indicates that water quality (pH and conductivity) is maintained in accordance with established guidance. However, per BWRVIP-130, "BWR Water Chemistry Guidelines," Section 8.2.1.11, pH measurement accuracy in most BWR streams is generally suspect because of the dependence of the instrument reading on ionic strength of the sample solution. In addition, the monitoring of pH is not discussed in BWRVIP-130, Appendix B for condensate storage tank, demineralized water storage tank, or torus water. pH is not monitored for torus water, however pH is monitored in the CST & DWST. Alternate methods are applied to monitor the water chemistry of the torus in lieu of direct pH measurements. The Oyster Creek chemistry procedures require monitoring of conductivity, chlorides and sulfates in accordance with limits set by BWRVIP-130.

The GALL Report identified the following recommendations for the ?scope of program" and ?parameters Monitored or Inspected" program element associated with the exception taken:

1. Scope of Program: The program includes periodic monitoring and control of known detrimental contaminants such as chlorides, fluorides (PWRs only), dissolved oxygen, and sulfate concentrations below the levels known to result in loss of material or cracking. Water chemistry control is in accordance with industry guidelines such as BWRVIP-29 (EPRI TR-103515) for water chemistry in BWRs, EPRI TR-105714 for primary water chemistry in PWRs, and EPRI TR-102134 for secondary water chemistry in PWRs.

3. Parameters Monitored or Inspected: The concentration of corrosive impurities listed in the EPRI guidelines discussed above, which include chlorides, fluorides (PWRs only), sulfates, dissolved oxygen, and hydrogen peroxide, are monitored to mitigate degradation of structural materials. Water quality (pH and conductivity) is also maintained in accordance with the guidance. Chemical species and water quality are monitored by in process methods or through sampling. The chemical integrity of the samples is maintained and verified to ensure that the method of sampling and storage will not cause a change in the concentration of the chemical species in the samples.

BWR Water Chemistry: The guidelines in BWRVIP-29 (EPRI TR-103515) for BWR reactor water recommend that the concentration of chlorides, sulfates, and dissolved oxygen are monitored and kept below the recommended levels to mitigate corrosion. The two impurities, chlorides and sulfates, determine the coolant conductivity; dissolved oxygen, hydrogen peroxide, and hydrogen determine electrochemical potential (ECP). The EPRI guidelines recommend that the coolant conductivity and ECP are also monitored and kept below the recommended levels to mitigate SCC and corrosion in BWR plants. The EPRI guidelines in BWRVIP-29 (TR-103515) for BWR feedwater, condensate, and control rod drive water recommend that conductivity, dissolved oxygen level, and concentrations of iron and copper (feedwater only) are monitored and kept below the recommended levels to mitigate SCC. The EPRI guidelines in BWRVIP-29 (TR-103515) also include recommendations for controlling water chemistry in auxiliary systems: torus/pressure suppression chamber, condensate storage tank, and spent fuel pool.

In reviewing this exception, the project team noted that OCGS monitors conductivity, chlorides, sulfates and total organic carbons (TOC) in the torus, per BWRVIP-130, Table B-3, which does not include pH as one of the parameters. The applicant was asked to explain the alternate method that is used to monitor pH in the torus water. In response, the applicant stated that a pH analysis of the torus water has been performed periodically and the torus water pH has been found to be near neutral (i.e., 6.6 – 7.4). This is based on measurements during the last five years (July 2001 – 6.7; March 2002 – 7.0; July 2003 – 6.9; April 2005 – 7.4; and June 2005 – 6.6). The applicant also stated that this pH analysis will continue during the period of extended operation.

The project team determined that the applicant has been routinely monitoring parameters suggested in the BWRVIP-130, and, in addition, the applicant is performing pH analysis of the torus water periodically to ensure its quality. On this basis, the project team found this exception acceptable.

<u>Exception 6</u>

Elements:	1. Scope of Program 4. Detection of Aging Effects
Exception:	Aging of Standby Liquid Control (SBLC) system components not in the reactor coolant pressure boundary section of SBLC system relies on monitoring and control of SBLC makeup water chemistry. The makeup water is monitored in lieu of the storage tank, because the sodium pentaborate that is maintained in the storage tank would mask most of the chemistry parameters monitored. The effectiveness of the Water Chemistry Program will be verified by a one-time inspection of the SBLC system as discussed in the One-Time Inspection (B.1.24) aging management program.

The GALL Report identified the following recommendations for the ?scope of program” and ?detection of aging effects” program elements associated with the exception taken:

> *1. Scope of Program:* The program includes periodic monitoring and control of known detrimental contaminants such as chlorides, fluorides (PWRs only), dissolved oxygen, and sulfate concentrations below the levels known to result in loss of material or cracking. Water chemistry control is in accordance with industry guidelines such as BWRVIP-29 (EPRI TR-103515) for water chemistry in BWRs, EPRI TR-105714 for primary water chemistry in PWRs, and EPRI TR-102134 for secondary water chemistry in PWRs.
>
> *4. Detection of Aging Effects:* This is a mitigation program and does not provide for detection of any aging effects.
>
> In certain cases as identified in the GALL Report, inspection of select components is to be undertaken to verify the effectiveness of the chemistry control program and to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period of operation.

As part of the audit, the project team interviewed the applicant's technical staff to discuss technical issues related to this exception. During the interview, the applicant stated that aging of Standby Liquid Control (SBLC) system components relies on monitoring and control of SBLC makeup water chemistry. The makeup water is monitored in lieu of the storage tank, because the sodium pentaborate that is maintained in the storage tank would mask most of the chemistry parameters monitored. The applicant claims that the effectiveness of the Water Chemistry Program will be verified by a one-time inspection of the SBLC system, as discussed in the one-time inspection aging management program (AMP B.1.24). The applicant was asked to confirm that the one-time inspection would consider the SBLC pump casing, and the associated tank discharge piping and valve bodies in addition to the tank. In its response, the applicant stated that one stainless steel sample of the entire system (including the piping and fittings, tanks, thermowells, and valve bodies) would be selected for thickness measurements and crack detection using a volumetric examination such as UT. Since the SBLC is a standby system, any section of pipe (with the smallest thickness when compared to valve and pump bodies or other pipe fittings) containing sodium pentaborate represents a ?worst-case" location.

The project team determined that the applicant would select a ?worst-case" sample from the SBLC system in the One-Time Inspection Program, which will provide assurance the aging effects for this system will be adequately managed. On this basis, the project team found this exception acceptable.

3.0.3.2.2.4 Enhancements

None

3.0.3.2.2.5 Operating Experience

In the OCGS LRA, the applicant stated that periodic self-assessments of the water chemistry activities have been, and continue to be performed to identify areas that need improvement to maintain the quality performance of the activity.

The Water Chemistry Program has identified instances where parameters were outside the established specifications. Increased sampling and actions to bring the parameters back into specification were initiated. The chemistry excursion is then documented in a condition report in accordance with plant administrative procedures. The corrective actions program ensures that the conditions adverse to quality are promptly corrected. If the deficiency is assessed to be significantly adverse to quality, the cause of the condition is determined and a corrective action plan is developed to preclude repetition. Some examples are as follows:

- The demineralized water system was contaminated due to a cross-connection with the fuel pool. The system was flushed and use of demineralized water required chemistry sampling to ensure that the water was 'clean'. A plan was developed to sample the demineralized water system from many locations. The completion of this plan enabled the demineralized water system to be declared 'clean' again.

- There have been some instances of reactor water sulfate levels exceeding ?Action Level 1" limits of 5 ppb. When this occurred, increased sampling was performed and corrective actions (such as placing 2 RWCU pump inservice) were implemented.

- A resin ingress caused by failure of the underdrain system occurred in one of the condensate demineralizers. This event was entered into the corrective action process and the apparent cause was determined to be due to incomplete work in the underdrain installation four years prior.

In its PBDs the applicant stated that a review of industry operating experience has confirmed that IGSCC has occurred in small and large diameter BWR piping made of austenitic stainless steels and nickel-based alloys. Significant cracking has occurred in recirculation, core spray, residual heat removal, and RWCU systems piping welds. IGSCC has also occurred in a number of vessel internal components, including core shroud, access hole cover, top guide, and core spray spargers as referenced in NRC Bulletin 80-13, IN 95-17, GL 94-03, and NUREG-1544. No occurrence of SCC in piping and other components in standby liquid control systems exposed to sodium pentaborate solution has ever been reported as referenced in NUREG/CR-6001.

The project team reviewed an OCGS self-assessment report titled ?Focus Area Self-Assessment Report, 4/13 – 4/16, 2004," which was performed during April 2004, and verified that it identified areas of improvements to maintain the performance quality of this AMP.

The project team reviewed the operating experience provided in the OCGS LRA, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant's Water Chemistry Program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.2.2.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the Water Chemistry Program in OCGS LRA, Appendix A, Section A.1.2, which states that the water chemistry aging management program is an existing program whose activities consist of monitoring and control of water chemistry to manage the aging of piping, piping components, piping elements and heat exchangers that are exposed to treated water to keep peak levels of various contaminants below system-specific limits based on industry-recognized guidelines of BWRVIP-130: ?BWR Vessel and Internals Project BWR Water Chemistry Guidelines" for the prevention or mitigation of loss of material, reduction of heat transfer and cracking aging effects. In addition, the Water Chemistry Program is also credited for mitigating loss of material and cracking for components exposed to sodium pentaborate and boiler treated water environments. To mitigate aging effects on component surfaces, the chemistry program is used to control water chemistry for impurities that accelerate corrosion.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.2, found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR UFSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.2.2.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report, are consistent with the GALL Report. In addition, the project team has reviewed the exceptions and their associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. The project team also reviewed the UFSAR Supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.3 Reactor Head Closure Studs (OCGS AMP B.1.3)

In OCGS LRA, Appendix B, Section B.1.3, the applicant stated that OCGS AMP B.1.3, "Reactor Head Closure Studs," is an existing plant program that is consistent with GALL AMP XI.M3, "Reactor Head Closure Studs," with an exception.

3.0.3.2.3.1 Program Description

The applicant stated, in the OCGS LRA, that this program provides for condition monitoring and preventive activities to manage stud cracking. The program is implemented through station procedures based on the examination and inspection requirements specified in ASME Section XI, Table IWB-2500-1 and preventive measures described in Regulatory Guide 1.65, ?Materials and Inspection for Reactor Vessel Closure Studs."

3.0.3.2.3.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.3 is consistent with GALL AMP XI.M3, with an exception.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.3, including PBD-AMP-B.1.03, "Reactor Head Closure Studs," Rev. 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M3. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.3 and associated bases documents to determine their consistency with GALL AMP XI.M3.

Also, the project team reviewed OCGS stud drawing CE 232-573, ?Stud, Nut, Washer, & Bushing Detail, Rev. 10 and its certified material test report (CMTR),Crucible Steel Company, ?Piece Number 573-01, Code Number G-385," dated 8/7/65, to confirm that the closure studs are constructed of ASME SA-193 GR. AISI 4340 material, which has a tensile strength of less than 170 ksi and complies with Regulatory Guide 1.65.

The project team reviewed those portions of the Reactor Head Closure Studs Program for which the applicant claims consistency with GALL AMP XI.M3 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's Reactor Head Closure Studs Program conforms to the recommendations in GALL AMP XI.M3, with the exception described below.

3.0.3.2.3.3 Exceptions to the GALL Report

In the OCGS LRA, the applicant stated the following exception to the GALL Report program elements:

Elements: 3: Parameters Monitored/ Inspected
4: Detection of Aging Effects

5: Monitoring and Trending
6: Acceptance Criteria

Exception: The current ASME code of record for ISI at Oyster Creek is the 1995 Edition through the 1996 Addenda.

The GALL Report identifies the following recommendation for the ?parameters monitored or inspected,” ?detection of aging effects,” ?monitoring and trending,” and acceptance criteria” program elements associated with the exception taken:

3. *Parameters Monitored or Inspected*: The ASME Section XI ISI program detects and sizes cracks, detects loss of material, and detects coolant leakage by following the examination and inspection requirements specified in Table IWB-2500-1.

4. *Detection of Aging Effects*: The extent and schedule of the inspection and test techniques prescribed by the program are designed to maintain structural integrity and ensure that aging effects will be discovered and repaired before the loss of intended function of the component. Inspection can reveal cracking, loss of material due to corrosion or wear, and leakage of coolant. The program uses visual, surface, and volumetric examinations in accordance with the general requirements of Subsection IWA-2000. Surface examination uses magnetic particle, liquid penetration, or eddy current examinations to indicate the presence of surface discontinuities and flaws. Volumetric examination uses radiographic or ultrasonic examinations to indicate the presence of discontinuities or flaws throughout the volume of material. Visual VT-2 examination detects evidence of leakage from pressure-retaining components, as required during the system pressure test.

Components are examined and tested as specified in Table IWB-2500-1. Examination category B-G-1 for pressure-retaining bolting greater than 2 in. diameter in reactor vessels specifies volumetric examination of studs in place, from the top of the nut to the bottom of the flange hole, and surface and volumetric examination of studs when removed. Also specified are volumetric examination of flange threads and visual VT-1 examination of surfaces of nuts, washers, and bushings. Examination category B-P for all pressure retaining components specifies visual VT-2 examination of all pressure-retaining boundary components during the system leakage test and the system hydrostatic test.

5. *Monitoring and Trending*: The Inspection schedule of IWB-2400, and the extent and frequency of IWB-2500-1 provide timely detection of cracks, loss of material, and leakage.

6. *Acceptance Criteria*: Any indication or relevant condition of degradation in closure stud bolting is evaluated in accordance with IWB-3100 by comparing ISI results with the acceptance standards of IWB-3400 and IWB-3500.

The applicant stated, in the OCGS LRA, that for justification of exceptions to the ISI program see the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program, AMP B1.1. The project team reviewed OCGS AMP B.1.1 and documented its acceptability in Section 3.0.3.2.1 of this report. On this basis, the project team found this exception acceptable.

3.0.3.2.3.4 Enhancements

None.

3.0.3.2.3.5 Operating Experience

The applicant stated, in the OCGS LRA, that Oyster Creek is currently in its fourth ISI inspection interval. In the history of the Oyster Creek ISI program no evidence of head stud cracking has been found. The reactor head closure studs, nuts, washers, and bushings have been coated with a manganese phosphate surface treatment. The operating experience for these components indicates that nicks, scratches, gouges, and thread damage have occurred due to maintenance activities during refueling outages. This normal wear type of damage was determined to be acceptable for continued service. There have been no deficiencies attributed to distortion/plastic deformation from stress relaxation or loss of material due to mechanical wear. This provides evidence that the aging management program is effective.

In its PBDs the applicant stated that a review of industry operating experience has confirmed that cracking due to SCC has occurred in reactor head studs. A review of plant operating experience at OCGS shows that cracking of the head studs from SCC, IGSCC, and loss of material due to wear has not occurred.

The project team reviewed the operating experience provided in the OCGS LRA, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant’s Reactor Head Closure Studs Program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.2.3.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the Reactor Head Closure Studs Program in OCGS LRA, Appendix A, Section A.1.3, which states that the Reactor Head Closure Studs Program is an existing program that provides for condition monitoring and preventive activities to manage stud cracking. The program is implemented through station procedures based on the examination and inspection requirements specified in ASME Section XI, Table IWB-2500-1 and preventive measures described in Regulatory Guide 1.65, ?Materials and Inspection for Reactor Vessel Closure Studs.”

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.3, found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.2.3.7 Conclusion

On the basis of its audit and review of the applicant’s program, the project team found that those program elements for which the applicant claims consistency with the GALL Report, are consistent with the GALL Report. In addition, the project team has reviewed the exception and the associated justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. The project team also reviewed the UFSAR Supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.4 BWR Vessel ID Attachment Welds (OCGS AMP B.1.4)

In OCGS LRA, Appendix B, Section B.1.4, the applicant stated that OCGS AMP B.1.4, "BWR Vessel ID Attachment Welds," is an existing plant program that is consistent with GALL AMP XI.M4, "BWR Vessel ID Attachment Welds," with exceptions.

3.0.3.2.4.1 Program Description

The applicant stated, in the OCGS LRA, that this program's activities incorporate the inspection and evaluation recommendations of BWRVIP-48, as well as the water chemistry recommendations of BWRVIP-130. The program is implemented through station procedures that provide for mitigation of cracking through water chemistry and monitoring for cracking through in-vessel examinations. Reactor vessel attachment weld inspections are implemented through station procedures that are part of in-service inspection and incorporate the requirements of ASME, Section XI. Inspections are performed in accordance with ASME requirements consistent with BWRVIP-48.

3.0.3.2.4.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.4 is consistent with GALL AMP XI.M4, with exceptions.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.4, including PBD-AMP-B.1.04, "BWR Vessel ID Attachment Welds," Rev. 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M4. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.4 and associated bases documents to determine their consistency with GALL AMP XI.M4.

Also, the project team reviewed OCGS Program Plan OC-5, ?Reactor Internals Program," Revision 0, 9/30/2005, which listed the long-term inspection schedule, requirements and inspection type for each individual component.

The inspection guidelines of BWRVIP-48 recommend enhanced visual VT-1 (EVT-1) examination of all safety-related attachments and those non-safety-related attachments identified as being susceptible to IGSCC. The applicant's examination plan applies EVT-1 for all of the ID attachment welds, regardless if the welds are known to be susceptible to IGSCC or not. The project team found this acceptable since the applicant's plan is more conservative than the GALL Report recommendation.

The project team reviewed those portions of the BWR Vessel ID Attachment Welds Program for which the applicant claims consistency with GALL AMP XI.M4 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's BWR Vessel ID Attachment Welds Program conforms to the recommended GALL AMP XI.M4, with the exceptions described below.

3.0.3.2.4.3 Exceptions to the GALL Report

In the OCGS LRA, the applicant stated the following exceptions to the GALL Report program elements:

Exception 1

Element: 2: Preventive Actions

Exception: NUREG-1801 indicates that water chemistry control is in accordance with BWRVIP-29 for water chemistry in BWRs. BWRVIP-29 references the 1993 revision of EPRI TR-103515, "BWR Water Chemistry Guidelines." The Oyster Creek Water Chemistry Programs are based on BWRVIP-130: ?BWR Vessel and Internals Project BWR Water Chemistry Guidelines", which is the 2004 revision of ?BWR Water Chemistry Guidelines". For justification of exceptions to the Water Chemistry Program see the Water Chemistry aging management program, B.1.2.

The GALL Report identified the following recommendation for the ?preventive actions" program element associated with the exception taken:

> 2. *Preventive Actions*: The BWRVIP-48 provides guidance on detection, but does not provide guidance on methods to mitigate cracking. Maintaining high water purity reduces susceptibility to SCC or IGSCC. Reactor coolant water chemistry is monitored and maintained in accordance with the guidelines in BWRVIP-29 (EPRI TR-103515). The program description and evaluation and technical basis of monitoring and maintaining reactor water chemistry are presented in Section XI.M2.

The applicant stated, in the OCGS LRA, that the Oyster Creek Water Chemistry Programs are based on BWRVIP-130: ?BWR Vessel and Internals Project BWR Water Chemistry Guidelines", which is the 2004 revision of ?BWR Water Chemistry Guidelines." For justification of exceptions to the Water Chemistry Program, see the water chemistry aging management program, AMP B.1.2. The project team reviewed AMP B.1.2 and documented its acceptability in Section 3.0.3.2.2 of this report. On this basis, the project team found this exception acceptable.

Exception 2

Elements: 3: Parameters Monitored/ Inspected
4: Detection of Aging Effects
5: Monitoring and Trending
6: Acceptance Criteria

Exception: NUREG-1801 program XI.M9 references ASME Section XI, Table IWB 2500-1 (2001 edition, including the 2002 and 2003 Addenda). Oyster Creek ISI program is based on the 1995 (including 1996 Addenda) version of ASME Section XI. For justification of exceptions to the ISI program see the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program, B1.1.

The GALL Report identifies the following recommendation for the above program elements associated with the exception taken:

> 3. *Parameters Monitored or Inspected*: The program monitors the effects of SCC and IGSCC on the intended function of vessel attachment welds by detection and sizing of cracks by ISI in accordance with the guidelines of approved BWRVIP-48 and the requirements of the ASME Code, Section XI, Table IWB 2500-1 (2001 edition3 including the 2002 and 2003 Addenda). An applicant may use the guidelines of BWRVIP-62 for inspection relief for vessel internal components with hydrogen water chemistry provided that such relief is submitted under the provisions of 10 CFR 50.55a and approved by the staff.
>
> 4. *Detection of Aging Effects:* The extent and schedule of the inspection and test techniques prescribed by BWRVIP-48 guidelines are designed to maintain structural integrity and ensure that aging effects will be discovered and repaired before the loss of intended function. Inspection can reveal cracking. Vessel ID attachment welds are inspected in accordance with the requirements of ASME Section XI, Subsection IWB, examination category B-2. The Section XI inspection specifies visual VT-1 examination to detect discontinuities and imperfections on the surfaces of components and visual VT-3 examination to determine the general mechanical and structural condition of the component supports. The inspection and evaluation guidelines of BWRVIP-48 recommend more stringent inspections for certain attachments. The guidelines recommend enhanced visual VT-1 examination of all safety-related attachments and those non-safety-related attachments identified as being susceptible to IGSCC. Visual VT-1 examination is capable of achieving 1/32 in. resolution; the enhanced visual VT-1 examination method is capable of achieving a 1-mil wire resolution. The NDE techniques appropriate for inspection of BWR vessel internals including the uncertainties inherent in delivering and executing NDE techniques in a BWR, are included in BWRVIP-03.
>
> 5. *Monitoring and Trending:* Inspections scheduled in accordance with IWB-2400 and approved BWRVIP-48 guidelines provide timely detection of cracks. If flaws are detected, the scope of examination is expanded.
>
> 6. *Acceptance* Criteria: Any indication detected is evaluated in accordance with ASME Section XI or the staff-approved BWRVIP-48 guidelines. Applicable and approved BWRVIP-14, BWRVIP-59, and BWRVIP-60 documents provide guidelines for evaluation of crack growth in stainless steels (SSs), nickel alloys, and low-alloy steels, respectively.

The project team reviewed this exception as part of its review of OCGS AMP-B.1.1, ?ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD” program and found it acceptable. The project team’s evaluation is documented in Section 3.0.3.2.1 of this audit and review report.

3.0.3.2.4.4 Enhancements

None.

3.0.3.2.4.5 Operating Experience

The applicant stated, in the OCGS LRA, that the Oyster Creek inspection and testing methodologies have not detected cracking in the attachment welds in the history of the Oyster Creek plant. This provides evidence that the Water Chemistry Program has been effective in minimizing the effects of stress corrosion cracking in the attachment welds. The same inspection and testing methodologies are used for the attachment welds as are used for other reactor internals. These processes have detected cracking in other vessel internal components.

The project team reviewed the summary of corrective action programs (CAP) provided in the program basis document. Those CAPs indicated that other aging management activities similar to those for the reactor vessel ID attachment welds have detected aging degradation with appropriate corrective actions implemented to maintain system and component intended functions, including prompt repair of degraded components prior to failure. The project team found that the applicant’s aging management activities appropriately addressed the aging effects for cracking due to IGSCC.

The project team also reviewed the operating experience provided in the OCGS LRA, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience, and discussions with the applicant's technical staff, the project team determined that the applicant’s BWR Vessel ID Attachment Welds Program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.2.4.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the BWR Vessel ID Attachment Welds Program in OCGS LRA, Appendix A, Section A.1.4, which states that the BWR Vessel ID Attachment Welds Program is an existing program that includes (a) inspection and flaw evaluation in conformance with the guidelines of staff-approved boiling water reactor vessel and internals project BWRVIP-48 and (b) monitoring and control of reactor coolant water chemistry in accordance with the guidelines of BWRVIP-130.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.4, found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.2.4.7 Conclusion

On the basis of its audit and review of the applicant’s program, the project team found that those program elements for which the applicant claims consistency with the GALL Report are consistent with the GALL Report. In addition, the project team has reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. The project team also reviewed the UFSAR Supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.5 BWR Feedwater Nozzle (OCGS AMP B.1.5)

In the OCGS LRA, Appendix B, Section B.1.5, the applicant stated that OCGS AMP B.1.5, ?BWR Feedwater Nozzle," is an existing plant program that is consistent with GALL AMP XI.M5, ?BWR Feedwater Nozzle," with exceptions and enhancements.

3.0.3.2.5.1 Program Description

In the OCGS LRA, the applicant stated that this program provides for monitoring of feedwater nozzles for cracking through station procedures based on the 1995 Edition through 1996 Addendum of ASME Section XI, Subsection IWB, Table IWB 2500-1. The program specifies periodic ultrasonic (UT) inspections of critical regions of the feedwater nozzle. The inspections are performed at intervals not exceeding ten years.

3.0.3.2.5.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.5 is consistent with GALL AMP XI.M5, with an exception and an enhancement.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.5, including the OCGS program basis document (PBD), PBD-AMP-B.1.05, ?BWR Feedwater Nozzle," Rev. 0, 12/09/2005, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M5. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.5 and associated bases documents to determine their consistency with GALL AMP XI.M5.

Also, the project team reviewed GE NE-523-A71-0594-A, ?Alternate BWR Feedwater Nozzle Inspection Requirement," Revision 1, August 1999 and Letter P. F. McKee (NRC) to J. J. Barton (GPU), ?Evaluation of the Request for Relief From NUREG-0619 for Oyster Creek Nuclear Generating Station (TAC No. M85751)" dated October 4, 1994.

In the PBD, the applicant stated that OCGS replaced the original feedwater spargers in 1977 to address industry-wide feedwater nozzle cracking issues in response to NUREG-0619. Each OCGS replacement feedwater sparger incorporated a piston ring seal at the single nozzle thermal sleeve to safe end connection, and included a flow baffle to better protect the low alloy steel nozzles. Also, OCGS removed stainless steel cladding at the feedwater nozzle areas and repaired all cracks found there. OCGS also changed the feedwater flow control system to improve system performance and reduce temperature fluctuations at the nozzle bend areas during low power operation. OCGS did not reroute the reactor water cleanup system. In accordance with NUREG-0619, OCGS performed liquid penetrant examination (PT) of the originally cladded surfaces to ensure that there were no cracks remaining in the nozzle area.

The applicant was asked to discuss the results of the PT examinations performed in 1977. In its response, the applicant stated that the PT examination of the nozzle area during the 1977 inspections detected 54 unacceptable flaws distributed among all four nozzles. Following clad removal of the nozzle inside surface, the inspections were repeated and revealed 12 smaller indications in three of the nozzles, as follows: 45-degree nozzle – 5 indications (0.5-1.5 inches long), 135-degree nozzle – no indications, 225-degree nozzle – 4 indications (0.3 to 3 inches long) and 315-degree nozzle – 3 indications (0.25 to 1 inch long). These indications were grounded out with pencil grinders and surface polished. Subsequent examinations have not identified any new indications.

The applicant also stated in its response that OCGS continued to perform visual inspections of the feedwater sparger during every subsequent refueling outage and found no sign of any degradation. During the 1988-89 refueling outage (12R), the applicant performed ultrasonic examinations (UT) from outside of all nozzle safe ends, bores, and inside blend radii in accordance with NUREG-0619, Section 4.3.2.3 (i.e., UT inspection and subsequent PT of recordable indications) and detected no reportable indications.

After submitting the above results to the staff in 1992 (Appendix VIII UT qualification), the applicant submitted a relief request to eliminate routine PT examination of the feedwater and CRD return line nozzles, as committed to earlier in response to NUREG-0619, and utilize the phased-array UT technique (most advanced method of UT at the time) as the primary method to detect, characterize, and monitor flaws in these nozzles. On October 4, 1994, the staff approved the applicant’s request for relief and since then the applicant has been performing UT examination of these nozzles in lieu of the PT examination recommended in NUREG-0619.

The project team recognized that relief requests typically apply only to the current inspection interval; therefore, they are not applicable to the period of extended operation and cannot be credited for that period. The applicant was asked to confirm that the relief approved in 1994 has no time limit. In its response, the applicant stated that this particular relief is from a commitment made to meet the recommendations of NUREG-0619 at the time, and has no time limit. Moreover, the applicant is still committed to perform PT examination, should any indications of cracking be found based on the UT examination, as required in NUREG-0619.

Subsequent to the aforementioned relief request, the BWR Owner’s Group (BWROG) submitted GE topical report GE-NE-523-A71-0594 to the staff. This report specifies a new advanced UT technique, and examination of specific regions of the nozzle blend radius and bore. On June 1998, the staff approved this BWR feedwater nozzle inspection report as an alternate to the recommendations set forth in NUREG-0619, subject to the conditions listed in the SER. On August 1999, the BWROG issued Revision 1 of GE topical report (GE-NE-523-A71-0594-A) after incorporating all recommendations listed in the SER. Chapter 4 of the GE report specifies ultrasonic testing (UT) requirements as the primary means of inspection. OCGS has committed to implementing the UT methodology recommended in the GE report to inspect the nozzle in future. This will include the standard performance demonstration initiative (PDI) UT methodology that meets the requirements of Appendix VIII of ASME Section XI. OCGS is planning to enhance its current augmented inspection program to meet this UT methodology and other conditions set forth by the staff SER prior to the period of extended operation.

The project team reviewed those portions of the BWR Vessel ID Attachment Welds Program for which the applicant claims consistency with GALL AMP XI.M5 and found that they are consistent with the GALL Report AMP. The project team found that the applicant’s BWR Vessel ID Attachment Welds Program conforms to the recommended GALL AMP XI.M, with the exception and enhancement described below.

3.0.3.2.5.3 Exceptions to the GALL Report

In the OCGS LRA, the applicant stated the following exception to the GALL Report program elements:

Elements:	1. Scope of Program 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring and Trending 6. Acceptance Criteria 7. Corrective Actions
Exception:	NUREG-1801 program XI.M5 references ASME Section XI, Table IWB 2500-1 (2001 edition, including the 2002 and 2003 Addenda). Oyster Creek ISI program is based the 1995 (including 1996 Addenda) version of ASME Section. For justification of exceptions to the ISI program see the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program, B1.1.

The GALL Report identified the following recommendations for the ?scope of program," ?parameters monitored or inspected," ?detection of aging effects," ?monitoring and trending," ?acceptance criteria," and ?corrective actions" program elements associated with the exception taken:

1. Scope of Program: The program includes enhanced ISI to monitor the effects of cracking on the intended function of the component, and systems modifications to mitigate cracking.

3. Parameters Monitored or Inspected: The aging management program (AMP) monitors the effects of cracking on the intended function of the component by detection and sizing of cracks by ISI in accordance with ASME Section XI, Subsection IWB and the recommendation of GE NE-523-A71-0594.

4. Detection of Aging Effects: The extent and schedule of the inspection prescribed by the program are designed to ensure that aging effects will be discovered and repaired before the loss of intended function of the component. Inspection can reveal cracking. GE NE-523-A71-0594 specifies ultrasonic testing (UT) of specific regions of the blend radius and bore. The UT examination techniques and personnel qualifications are in accordance with the guidelines of GE NE-523-A71-0594. Based on the inspection method and techniques and plant-specific fracture mechanics assessments, the inspection schedule is in accordance with Table 6-1 of GE NE-523-A71-0594. Leakage monitoring may be used to modify the inspection interval.

5. Monitoring and Trending: Inspections scheduled in accordance with GE NE-523-A71-0594 provide timely detection of cracks.

6. *Acceptance Criteria:* Any cracking is evaluated in accordance with IWB-3100 by comparing inspection results with the acceptance standards of IWB-3400 and IWB-3500.

7. Corrective Actions: Repair is performed in conformance with IWB-4000 and replacement in accordance with IWB-7000. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

In reviewing this exception, the project team recognized that, in accordance with note 4 to AMP XI.M5 in the GALL Report, ?An applicant may rely on a different version of the ASME Code, but should justify such use. An applicant may wish to refer to the SOC (statements of consideration) for an update of 10 CFR § 50.55a to justify use of a more recent edition of the Code."

The project team also recognized that 10 CFR 50.55a is revised periodically to adopt, by reference, new editions and addenda of the ASME Code. For each successive 120-month (10 year) inspection interval, applicants are required to revise the nuclear plant's ISI program to incorporate the requirements specified in the version of the ASME Code referenced in 10 CFR 50.55.a 12 months prior to the start of the inspection interval.

In the OCGS LRA, the applicant stated that at present, the Oyster Creek is committed to the 1995 version (including 1996 addenda) of the ASME Section XI Code during its fourth ten-year inspection interval, which is effective from October 15, 2002 through October 14, 2012, approved per 10 CFR 50.55a. The next 120-month inspection interval will incorporate the requirements specified in the version of the ASME Code referenced in 10 CFR 50.55a 12 months prior to the start of the inspection interval.

Also, the project team noted that the 1995 or later version of the ASME Section XI Code does not contain sections IWB-4000 for repair and IWB-7000 for replacement, as stated in the GALL Report. Instead, repair and replacement are performed in conformance with IWA-4000, as discussed in the OCGS basis document. This is consistent with the ASME Section XI Code used by OCGS at this time.

The current OCGS ISI program is based on the 1995 version (including 1996 addenda) of the ASME Section XI and the program will be updated in accordance with 10 CFR 50.55a after each 10 year interval to meet the GALL-recommended Code (2001 edition, including the 2002 and 2003 Addenda). On this basis, the project team determined that this exception is acceptable.

3.0.3.2.5.4 Enhancements

In the OCGS LRA, the applicant identified the following enhancement in order to meet the GALL Report program elements:

Elements:
1. Scope of Program
3. Parameters Monitored or Inspected
4. Detection of Aging Effects
5. Monitoring and Trending

Enhancement: The Oyster Creek Feedwater Nozzle aging management program will be enhanced to implement the recommendations of the BWR Owners Group Licensing Topical Report General Electric (GE) NE-523-A71-0594. These enhancements will be implemented prior to entering the period of extended operation.

The GALL Report identified the following recommendations for the ?scope of program," ?parameters monitored or inspected," ?detection of aging effects," and ?monitoring and trending" program elements associated with the enhancement taken:

> *1. Scope of Program:* The program includes enhanced ISI to monitor the effects of cracking on the intended function of the component, and systems modifications to mitigate cracking.
>
> *3. Parameters Monitored or Inspected:* The aging management program (AMP) monitors the effects of cracking on the intended function of the component by detection and sizing of cracks by ISI in accordance with ASME Section XI, Subsection IWB and the recommendation of GE NE-523-A71-0594.
>
> *4. Detection of Aging Effects:* The extent and schedule of the inspection prescribed by the program are designed to ensure that aging effects will be discovered and repaired before the loss of intended function of the component. Inspection can reveal cracking. GE NE-523-A71-0594 specifies ultrasonic testing (UT) of specific regions of the blend radius and bore. The UT examination techniques and personnel qualifications are in accordance with the guidelines of GE NE-523-A71-0594. Based on the inspection method and techniques and plant-specific fracture mechanics assessments, the inspection schedule is in accordance with Table 6-1 of GE NE-523-A71-0594. Leakage monitoring may be used to modify the inspection interval.
>
> *5. Monitoring and Trending:* Inspections scheduled in accordance with GE NE-523-A71-0594 provide timely detection of cracks.

In the OCGS LRA, the applicant stated that OCGS is committed to implementing the recommendations in NE-523-A71-0594, Revision 1, prior to entering the period of extended operation. The applicant's BWR Vessel ID Attachment Welds Program AMP will be enhanced to include the recommendations of the BWR owners group licensing topical report General Electric (GE) NE-523-A71-0594, Revision 1, which includes UT examination of specific regions of the nozzle blend radius and bore region, UT methodology and personnel qualifications, and fracture mechanics methodology.

The project team reviewed the OCGS ISI Program Plan, OC-1 and found that it has not been updated in the section for the feedwater nozzle inspections since the commitments were made in response to NUREG-0619. Therefore, the applicant was asked to confirm that the UT examination specified in the GE topical report will be included in this ISI program plan. In its response, the applicant stated that the OCGS ISI Program Plan, OC-1, will be revised at the time this AMP is enhanced, which will be prior to starting the extended period of operation.

On this basis, the project team found this enhancement acceptable since when the enhancement is implemented OCGS AMP B.1.5, ?BWR Feedwater Nozzle," will be consistent with GALL AMP XI.M5.

3.0.3.2.5.5 <u>Operating Experience</u>

In the OCGS LRA, the applicant stated that Oyster Creek inspected the feedwater nozzles in 1977 in response to industry experience at that time. Cracks were found in the nozzles and repaired. To minimize thermal cycling and fatigue induced cracking the thermal sleeve was modified with a piston type design. Subsequent inspections, the most recent in 2000, have found no indication of cracking in the feedwater nozzle. This provides evidence that the thermal sleeve modification has been effective in mitigating the effects of thermal fatigue on the feedwater nozzles.

The project team reviewed past inspection results of the feedwater nozzles since OCGS implemented NUREG-0619 recommendations and found that the UT examination of the nozzle area revealed no new indications. Also, the applicant has been routinely performing inspections of the feedwater spargers and no such degradation of the replacement spargers was noted. Although the applicant claims that the VT-3 visual inspection of the sparger flow holes and welds in the sparger tees and sparger arm are being performed at a frequency of at least once every fourth refueling outage, as required in NUREG-0619, the project team did not find any evidence of this finding. However, the applicant will enhance the BWR Vessel Internals Program (B.1.9) to include and document the conditions of the feedwater nozzle, as well as the CRD return line nozzle thermal sleeves.

The project team reviewed the operating experience provided during the audit, and interviewed the applicant's technical staff to confirm that since the recommendations of NUREG-0619 were implemented, including the installation of replacement feedwater spargers, this program has not detected any cracks in the feedwater nozzle regions at OCGS.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant's BWR Vessel ID Attachment Welds Program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.2.5.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the BWR Vessel ID Attachment Welds Program in OCGS LRA, Appendix A, Section A.1.5, which states that the BWR Vessel ID Attachment Welds Program aging management program is an existing program that provides for monitoring of feedwater nozzles for cracking through station procedures based on the 1995 Edition through 1996 Addendum of ASME Section XI, Subsection IWB, Table IWB 2500-1. The program specifies periodic ultrasonic (UT) inspections of critical regions of the feedwater nozzle. The inspections are performed at intervals not exceeding ten years.

The Oyster Creek Vessel ID Attachment Welds Program aging management program will be enhanced to implement the recommendations of the BWR Owners Group Licensing Topical Report General Electric (GE) NE-523-A71-0594. These enhancements will be implemented prior to entering the period of extended operation.

The project team also reviewed the applicant's license renewal commitment list in Appendix A of the OCGS LRA, and confirmed that the enhancements to this program are identified and will be implemented prior to the period of extended operation as item 5 of the commitments.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.5, and found that it was consistent with the GALL Report, and determined that it provided an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.2.5.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report, are consistent with the GALL Report. In addition, the project team has reviewed the exception and the associated justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. Also, the project team has reviewed the enhancement and determined that the implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The project team also reviewed the UFSAR Supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.6 BWR Control Rod Drive Return Line Nozzle (OCGS AMP B.1.6)

In the OCGS LRA, Appendix B, Section B.1.6, the applicant stated that OCGS AMP B.1.6, "BWR Control Rod Drive Return Line Nozzle," is an existing plant program that is consistent with GALL AMP XI.M6, "BWR Control Rod Drive Return Line Nozzle," with exceptions.

3.0.3.2.6.1 Program Description

In the OCGS LRA, the applicant stated that this program provides for monitoring of the Control Rod Drive Return Line Nozzle for cracking through station ISI procedures based on ASME Section XI, augmented by inspections performed in accordance with the inspection recommendations of NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking." Oyster Creek requested and received relief from the NRC for the recommendation of NUREG–0619 to perform ultrasonic examination testing in lieu of periodic dye penetrant testing. The inspections will be performed at intervals not exceeding ten years.

3.0.3.2.6.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.6 is consistent with GALL AMP XI.M6, with exceptions.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.6, including the OCGS program basis document, PBD-AMP-B.1.06, ?BWR CRD Return Line Nozzle," Rev. 0, 12/08/2005, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M6. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.6 and associated bases documents to determine their consistency with GALL AMP XI.M6.

The applicant was asked to discuss the activities performed at the current time in response to NUREG-0619. In its response, the applicant stated that OCGS removed the original control rod drive return line (CRDRL) nozzle thermal sleeve and performed a dye penetrant examination (PT) on the inside diameter of the nozzle in 1977 (7R outage) to address industry-wide CRDRL nozzle cracking issues in response to NUREG-0619. No indication of cracking was observed at the time. The applicant also stated that after finding no indications, the CRDRL nozzle thermal sleeve was replaced with a newly designed thermal sleeve that directed the flow farther into the downcomer region and away from the nozzle area. The new thermal sleeve is a one inch schedule 40 pipe that is attached to the remaining portion of the removed thermal sleeve by an interference fit. The one inch pipe increases fluid velocity to minimize the possibility of reentry of hot reactor recirculation flow back into the thermal sleeve, which carries cold CRD water at 100˚F

The project team noted that the applicant continued to perform visual inspections of the CRDRL nozzle during every subsequent refueling outage and found no sign of degradation. During the 1991 refueling outage (13R), the applicant performed ultrasonic examinations (UT) from outside of the nozzle in accordance with NUREG-0619, Section 4.3.2.3 (i.e., UT inspection and subsequent PT of recordable indications) and detected no reportable indications.

The project team reviewed those portions of the BWR Control Rod Drive Return Line Nozzle Program for which the applicant claims consistency with GALL AMP XI.M6 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's BWR Control Rod Drive Return Line Nozzle Program conforms to the recommendations in GALL AMP XI.M6, with the exceptions described below.

3.0.3.2.6.3 Exceptions to the GALL Report

In the OCGS LRA, the applicant stated the following exceptions to the GALL Report program elements:

Exception 1

Elements:	3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring and Trending 6. Acceptance Criteria 7. Corrective Actions
Exception:	NUREG-1801 program XI.M6 references ASME Section XI, Table IWB 2500-1 (2001 edition, including the 2002 and 2003 Addenda). Oyster Creek ISI program is based the 1995 (including 1996 Addenda) version of ASME Section XI. For justification of exceptions to the ISI program see the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program, B1.1.

The GALL Report identified the following recommendations for the ?parameters Monitored or Inspected," ?detection of aging effects," ?monitoring and trending," ?acceptance criteria," and ?corrective actions" program elements associated with the exception taken:

3. Parameters Monitored/ Inspected: The aging management program (AMP) monitors the effects of cracking on the intended function of the CRDRL nozzles by detecting and sizing cracks by ISI in accordance with Table IWB 2500-1 and NUREG-0619.

4. Detection of Aging Effects: The extent and schedule of inspection, as delineated in NUREG-0619, assures detection of cracks before the loss of intended function of the CRDRL nozzles. Inspection recommendations include liquid penetrant testing (PT) of CRDRL nozzle blend radius and bore regions and the reactor vessel wall area beneath the nozzle, return-flow-capacity demonstration, CRD-system-performance testing, and ultrasonic inspection of welded connections in the rerouted line. The inspection is to include base metal to a distance of one-pipe-wall thickness or 0.5 in., whichever is greater, on both sides of the weld.

5. Monitoring and Trending: The inspection schedule of NUREG-0619 provides timely detection of cracks.

6. *Acceptance Criteria:* Any cracking is evaluated in accordance with IWB-3100 by comparing inspection results with the acceptance standards of IWB-3400 and IWB-3500. All cracks found in the CRDRL nozzles are to be removed by grinding.

7. Corrective Actions: Repair is performed in conformance with IWB-4000 and replacement in accordance with IWB-7000. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

In accordance with GALL note 5 to this AMP, ?An applicant may rely on a different version of the ASME Code, but should justify such use. An applicant may wish to refer to the SOC (statements of consideration) for an update of 10 CFR § 50.55a to justify use of a more recent edition of the Code."

The project team noted that 10 CFR 50.55a is revised periodically to adopt, by reference, new editions and addenda of the ASME Code. For each successive 120-month (10 year) inspection interval, applicants are required to revise the nuclear plant's ISI program to incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a 12 months before the start of the inspection interval.

At present, the applicant is committed to the 1995 version (including 1996 addenda) of the ASME Section XI Code during its fourth ten-year inspection interval effective from October 15, 2002 through October 14, 2012, approved per 10CFR50.55a. The next 120-month inspection interval will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a 12 months before the start of the inspection interval.

Also, the project team noted that the 1995 or later version of the ASME Section XI does not contain sections IWB-4000 for repair and IWB-7000 for replacement, as stated in the GALL. Instead, repair and replacement are performed in conformance with IWA-4000, as discussed in the OCGS basis document. This is consistent with the ASME Section XI Code used by OCGS at this time.

The current OCGS ISI program is based on the 1995 version (including 1996 addenda) of ASME Section XI and the program will be updated in accordance with 10 CFR 50.55a after each 10 year interval to meet the GALL-recommended Code (2001 edition, including the 2002 and 2003 Addenda). On this basis, the project team determined that this exception is acceptable.

Exception 2

Elements: 3. Parameters Monitored or Inspected
4. Detection of Aging Effects
5. Monitoring and Trending

Exception: The Oyster Creek augmented ISI program for the CRD return line nozzle performs ultrasonic examination (UT) testing in lieu of dye penetrant testing (PT). Oyster Creek requested and received relief from the NRC to perform ultrasonic examination (UT) testing in lieu of the periodic PT testing [recommendations] specified in NUREG 0619.

The GALL Report identifies the following recommendations for the ?parameters monitored or inspected," ?detection of aging effects," and ?monitoring and trending" program elements associated with the exception taken:

3. Parameters Monitored or Inspected: The aging management program (AMP) monitors the effects of cracking on the intended function of the CRDRL nozzles by detecting and sizing cracks by ISI in accordance with Table IWB 2500-1 and NUREG-0619.

4. Detection of Aging Effects: The extent and schedule of inspection, as delineated in NUREG-0619, assures detection of cracks before the loss of intended function of the CRDRL nozzles. Inspection recommendations include liquid penetrant testing (PT) of CRDRL nozzle blend radius and bore regions and the reactor vessel wall area beneath the nozzle, return-flow-capacity demonstration, CRD-system-performance testing, and ultrasonic inspection of welded connections in the rerouted line. The inspection is to include base metal to a distance of one-pipe-wall thickness or 0.5 in., whichever is greater, on both sides of the weld.

5. Monitoring and Trending: The inspection schedule of NUREG-0619 provides timely detection of cracks.

As discussed in Section 3.0.3.2.5.2 of this audit and review report, in 1992 the applicant submitted a relief request to eliminate routine PT examination of the feedwater and CRD return line nozzles, as committed to earlier in response to NUREG-0619, and utilize the phased-array UT technique (most advanced method of UT at the time) as the primary method to detect, characterize and monitor flaws in these nozzles. On October 4, 1994, the staff approved the applicant's request for relief and since then the applicant has been performing UT examination of these nozzles in lieu of the PT examination recommended in NUREG-0619.

The project team recognized that relief requests typically apply only to the current inspection interval; therefore, they are not applicable to the period of extended operation and cannot be credited for that period. The applicant was asked to confirm that the relief approved in 1994 has no time limit. In its response, the applicant stated that this particular relief is from a commitment made to meet the NUREG-0619 at the time and has no time limit. Moreover, periodic CRDRL nozzle inspections are performed using qualified UT techniques at least once every 10-year period (120 months). The inspection interval is based on fatigue crack growth analyses performed in accordance with the methodology in Section XI of the ASME Code. Should UT examination results indicate the presence of a flaw exceeding the ASME Code allowable crack size, OCGS is committed to perform a PT inspection in the vicinity of the indication to verify the results. Qualification testing by the inspection vendor has demonstrated that the UT technique can reliably detect and size flaws in the areas of interest. Modification to the CRDRL nozzle thermal sleeve has played a major role in the prevention of CRDRL nozzle cracks.

The project team noted that the CRDRL nozzle is included in the Oyster Creek ISI program plan under Category B-D, ?Full Penetration Welds of Nozzles in Vessels," consistent with the requirements of Table IWB 2500-1. Augmented inspections are performed in accordance with NUREG-0619, ?BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle" recommendations.

The project team reviewed the OCGS ISI Program Plan, OC-1, and found that it has not been updated in the section for the CRDRL nozzle inspections since the commitments were made in response to NUREG-0619. The applicant was asked to confirm that the UT examination technique included in the relief request, or the most advanced technique (Appendix VIII UT qualification), will be included in the OCGS ISI program plan. In its response, the applicant stated that the OCGS ISI Program Plan, OC-1, will be revised to reflect the CRDRL nozzle inspections prior to entering the extended period of operation.

The project team determined that the current OCGS ISI program includes the recommendations given in NUREG-0619, and is consistent with the GALL-recommended guidelines. On this basis, the project team determined that this exception is acceptable.

<u>Exception 3</u>

Elements:	6. Acceptance Criteria 7. Corrective Actions
Exception:	NUREG-1801, XI.M6, specifies any detected crack be ground out. Oyster Creek procedures allow a crack that is found unacceptable under IWB-3400 and IWB-3500 to be evaluated under ASME XI, IWB-3600 or repaired by an NRC approved procedure.

The GALL Report identified the following recommendations for the ?acceptance criteria" and ?corrective actions" program elements associated with the exception taken:

> *6. Acceptance Criteria:* Any cracking is evaluated in accordance with IWB-3100 by comparing inspection results with the acceptance standards of IWB-3400 and IWB-3500. All cracks found in the CRDRL nozzles are to be removed by grinding.
>
> *7. Corrective Actions:* Repair is performed in conformance with IWB-4000 and replacement in accordance with IWB-7000. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

The applicant was asked to clarify the OCGS position stated in this exception. The applicant responded that all indications and relevant conditions detected during past examinations at OCGS were evaluated in accordance with ASME Section XI Subsection IWB-3100, for Class 1 components, using the criteria of IWB-3512. When a flaw exceeded the applicable acceptance standards of IWB-3400 or IWB-3500,a plant condition report was initiated in accordance with applicable procedures. An analytical evaluation was performed in accordance with IWB-3600 or an approved repair was performed in accordance with plant procedure ER-AA-330-002. In either case, NRC's approval was required prior to resumption of operation.

The applicant also stated that NUREG-0619 recommends any cracks found during the initial NUREG-0619 inspection be grounded out, unless clad removal is performed. However, the

NUREG does not provide guidance if flaws are found in the subsequent inspections. OCGS inspections during 1977 and subsequent inspections have not found any flaw indications in the CRDRL nozzle. The applicant has been following the OCGS ISI guidelines for this nozzle inspection as stated above. According to these guidelines, repairs are performed if the flaw does not meet the requirements of IWB-3600, in which case crack repairs may use the grind out option.

The project team noted that the 1995 or later version of the ASME Section XI does not contain sections IWB-4000 for repair and IWB-7000 for replacement as stated in the GALL. Instead, repair and replacement are performed in accordance with IWA-4000, as discussed in the OCGS program basis document for this AMP.

On this basis, the project team determined that this exception is acceptable.

3.0.3.2.6.4 Enhancements

None.

3.0.3.2.6.5 Operating Experience

In the OCGS LRA, the applicant stated that Oyster Creek inspected the CRD nozzle in 1977 in response to industry experience at that time. No cracks were found in the nozzle. To minimize thermal cycling and fatigue induced cracking, the thermal sleeve was modified to divert the relatively cold CRD flow away from the nozzle. The most recent inspection of the nozzle in 2002 confirms the lack of cracking in the nozzle area. This provides good evidence that the thermal sleeve modification has been effective in mitigating the effects of thermal fatigue on the CRD nozzle.

The project team reviewed past inspection results of the CRD return line nozzle since OCGS implemented NUREG-0619 recommendations and found that the UT examination of the nozzle area revealed no new indications. Also, the applicant has been routinely performing visual inspections of the nozzle thermal sleeve area and no such degradation of the replacement thermal sleeve was noted.

The project team reviewed the operating experience provided during the audit, and interviewed the applicant's technical staff to confirm that since the recommendations of NUREG-0619 were implemented, including the installation of replacement nozzle thermal sleeve, this program has not detected any cracks in the CRDRL nozzle regions at OCGS.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant’s BWR Control Rod Drive Return Line Nozzle Program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.2.6.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the BWR Control Rod Drive Return Line Nozzle Program in OCGS LRA, Appendix A, Section A.1.6 which states that the BWR control rod drive return line nozzle aging management program is an existing program that provides for monitoring of the control rod drive return line nozzle for cracking through station procedures based on ASME Section XI, Subsection IWB, Table IWB 2500-1, augmented by inspections performed in accordance with the inspection recommendations of NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking." Based on an NRC approved relief request, the periodic dye penetrant tests required by NUREG-0619 have been replaced by ultrasonic measurements. The inspections will be performed at intervals not exceeding ten years. Modifications were made to the control rod drive return line nozzle thermal sleeve to mitigate or prevent thermally induced fatigue cracking.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.6, found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.2.6.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report, are consistent with the GALL Report. In addition, the project team has reviewed the exceptions and their associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. The project team also reviewed the UFSAR Supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.7 BWR Stress Corrosion Cracking (OCGS AMP B.1.7)

In the OCGS LRA, Appendix B, Section B.1.7, the applicant stated that OCGS AMP B.1.7, "BWR Stress Corrosion Cracking," is an existing plant program that is consistent with GALL AMP XI.M7, "BWR Stress Corrosion Cracking," with one exception.

3.0.3.2.7.1 Program Description

In the OCGS LRA, the applicant stated that this program mitigates IGSCC in stainless steel reactor coolant pressure boundary piping components and piping four inches and greater nominal pipe size exposed to reactor coolant above 200°F. Preventive measures include monitoring and controlling of water impurities by water chemistry activities and providing replacement stainless steel components in the solution annealed condition with a maximum carbon content of 0.035 wt. % and a minimum ferrite level of 7.5 wt. %. Inspection and flaw evaluation are conducted in accordance with the inservice inspection program plan for the station.

The applicant also stated that the program is implemented through station procedures based on NUREG- 0313, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping Rev. 2," GL 88-01, "NRC Position on Intergranular Stress Corrosion Cracking (IGSCC) in BWR Austenitic Stainless Steel Piping," and its Supplement 1, BWRVIP-75, "Technical Basis for Revisions to GL 88-01 Inspection Schedules," BWRVIP-130, ?BWR Vessel and Internals Project BWR Water Chemistry Guidelines," and ASME Section XI.

3.0.3.2.7.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.7 is consistent with GALL AMP XI.M7, with one exception.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.7, including the OCGS program basis document, PBD-AMP-B.1.07, ?BWR Stress Corrosion Cracking," Rev. 0, 12/19/2005, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M7. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.7 and associated bases documents to determine their consistency with GALL AMP XI.M7.

The applicant was asked to provide details of all weld repairs and material replacement of components that occurred in order to implement the NUREG-0313 and GL 88-01 recommendations. The applicant responded that the following piping was replaced with IGSCC resistant material (low carbon stainless steel): a) all isolation condenser large bore piping outside the drywell (from the drywell penetrations to the isolation condensers), including new stress-improved welds; b) all piping within the four isolation condenser drywell penetrations and the two RWCU system drywell penetrations, which contain welds that are not inspectable; c) the isolation condenser piping at the isolation condensers on 95 feet elevation; d) the head cooling spray nozzle assembly; and e) the 4 inch tee and flange of the reactor vent line. Additionally, all accessible/ inspectable welds inside the drywell (except RWCU system) were stress improved.

The applicant also stated that, of the 380 welds in the scope of GL 88-01, which includes 85 in the RWCU system outside the second containment isolation valves, 40 welds were identified with IGSCC indications. Following numerous piping replacements, 11 welds remained in service with indications of IGSCC. Nine welds were repaired with full structural overlays (4 in core spray, 4 in recirculation and 1 in shutdown cooling systems). The remaining two welds were in service without repair in the recirculation system, however, they were both stress improved before inspections found IGSCC. After the implementation of the NRC-approved Performance Demonstration Initiative (PDI) inspections in 2002 and 2004 using the new UT technique, it was determined that there were no indications of IGSCC in either of the recirculation system welds.

The project team reviewed the OCGS program plan (OC-2: Program Plan – IGSCC Inspection Program, Rev. 0, 07/31/2003) for implementing the GL 88-01 and BWRVIP-75 recommendations. The program plan did not reference BWRVIP-14, 59, or 60 for guidance on the evaluation of crack growth in stainless steel, nickel alloys, and low alloy steel components, respectively. In response to a previous audit question, the applicant confirmed that these documents are in use at the OCGS IGSCC program. Thus, the applicant has fully implemented the NRC programs and has been inspecting the relevant piping in accordance with NRC-approved BWRVIP-75 since the BWR SCC program was first implemented.

With regards to the program element for ?corrective actions," the GALL Report stated that the guidance for weld overlay repair and stress improvement or replacement is provided in NRC GL 88-01; ASME Section XI, Subsections IWB-4000 and IWB-7000, IWC-4000 and IWC-7000, or IWD-4000 and IWD-7000, respectively, for Class 1, 2, or 3 components; and ASME Code Case N-504-1. These ASME Section XI subsections in earlier editions (1986 edition) have been replaced by subsections IWA-4000 in the later editions of the ASME Code. The OCGS ISI program currently performs its corrective action requirements in accordance with IWA-4000 of the 1995 edition of the Code. The project team found this acceptable since it is consistent with the version of the ASME Section XI Code currently applicable to Oyster Creek.

The project team reviewed those portions of the BWR stress corrosion cracking program for which the applicant claims consistency with GALL AMP XI.M7 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's BWR stress corrosion cracking program conforms to the recommended GALL AMP XI.M7, with the exception and the enhancement described below.

3.0.3.2.7.3 Exceptions to the GALL Report

In the OCGS LRA, the applicant stated the following exception to the GALL Report program element:

Element: 2. Preventive Actions

Exception: NUREG-1801 indicates that water chemistry control is in accordance with BWRVIP-29 for water chemistry in BWRs. BWRVIP-29 references the 1996 revision of EPRI TR- 103515, "BWR Water Chemistry Guidelines." The Oyster Creek Water Chemistry Program is based on BWRVIP-130, ?BWR Vessel and Internals Project BWR Water Chemistry Guidelines – 2004 Revision." For justification of exceptions, see Water Chemistry Program, B.1.2.

The GALL Report identifies the following recommendations for the ?preventive actions" program element associated with the exception taken:

2. Preventive Action: The comprehensive program outlined in NUREG-0313 and NRC GL 88-01 addresses improvements in all three elements that, in combination, cause IGSCC. These elements consist of a susceptible (sensitized) material, a significant tensile stress, and an aggressive environment. Sensitization of nonstabilized austenitic SSs containing greater than 0.03 wt.% carbon involves precipitation of chromium carbides at the grain boundaries during certain fabrication or welding processes. The formation of carbides creates an envelope of chromium depleted region that, in certain environments, is susceptible to SCC. Residual tensile stresses are introduced from fabrication processes, such as welding, surface grinding, or forming. High levels of dissolved oxygen or aggressive contaminants, such as sulfates or chlorides, accelerate the SCC processes.

The program delineated in NUREG-0313, NRC GL 88-01, and in the staff-approved BWRVIP-75 report includes recommendations regarding selection of materials that are resistant to sensitization, use of special processes that reduce residual tensile stresses, and monitoring and maintenance of coolant chemistry. The resistant materials are used for new and replacement components and include low-carbon grades of austenitic SS and weld metal, with a maximum carbon content of 0.035 wt.% and a minimum ferrite content of 7.5% in weld metal and cast austenitic stainless steel (CASS). Inconel 82 is the only commonly used nickel-base weld metal considered to be resistant to SCC; other nickel-alloys, such as Alloy 600 are evaluated on an individual basis. Special processes are used for existing, individual basis. Special processes are used for existing, new, and replacement components. These processes include solution heat treatment, heat sink welding, induction heating, and mechanical stress improvement.

> The program delineated in NUREG-0313 and NRC GL 88-01 does not provide specific guidelines for controlling reactor water chemistry to mitigate IGSCC. Maintaining high water purity reduces susceptibility to SCC or IGSCC. The program description, and evaluation and technical basis of monitoring and maintaining reactor water chemistry are addressed through implementation of Section XI.M2.

In Attachment 1, Item B.1.7 of its reconciliation document, the applicant stated that the above exception for OCGS AMP B.1.7 is no longer required and will be withdrawn. The applicant was asked to clarify the reason for withdrawing this exception. In its response, the applicant stated that AMP XI.M7 in the September 2005 GALL Report, to which OCGS AMP B.1.7 was compared, no longer makes reference to BWRVIP-29; therefore, this exception no longer applies to OCGS AMP B.1.7.

The project team verified that the reactor coolant water chemistry at OCGS is monitored and maintained in accordance with the guidelines in BWRVIP-130, ?BWR Vessel and Internals Project BWR Water Chemistry Guidelines" to maintain high water purity to reduce susceptibility to SCC or IGSCC. The project team reviewed the OCGS Water Chemistry Program (AMP B.1.2) and concluded that the use of BWRVIP-130 is acceptable. The project team's evaluation of OCGS AMP B.1.2 is discussed in Section 3.0.3.2.2 of this audit and review report. On this basis, the project team determined that the above exception is not required, and concurred with the applicants decision to withdraw the exception.

3.0.3.2.7.4 Enhancements

In the OCGS LRA, the applicant stated that there are no enhancements for this AMP. However, in the program basis document, PBD-AMP B.1.07, the applicant identified the following enhancement in order to meet the GALL Report program elements, which is not included in the OCGS LRA:

Element:	2. Preventive Actions
Enhancement:	The program will be enhanced to require that, for those components within the scope of the BWR Stress Corrosion Cracking aging management program, all new and replacement SS materials be low-carbon grades of SS with carbon content limited to 0.035 wt. % maximum and ferrite content limited to 7.5% minimum.

The GALL Report identifies the following recommendations for the ?preventive actions" program element associated with the enhancement taken:

> *2. Preventive Action*: The comprehensive program outlined in NUREG-0313 and NRC GL 88-01 addresses improvements in all three elements that, in combination, cause IGSCC. These elements consist of a susceptible (sensitized) material, a significant tensile stress, and an aggressive environment. Sensitization of nonstabilized austenitic SSs containing greater than 0.03 wt.% carbon involves precipitation of chromium carbides at the grain boundaries during certain fabrication or welding processes. The formation of carbides creates an envelope of chromium depleted region that, in certain environments, is susceptible to SCC. Residual tensile stresses are introduced from fabrication processes, such as welding, surface grinding, or forming. High levels of

dissolved oxygen or aggressive contaminants, such as sulfates or chlorides, accelerate the SCC processes.

The program delineated in NUREG-0313, NRC GL 88-01, and in the staff-approved BWRVIP-75 report includes recommendations regarding selection of materials that are resistant to sensitization, use of special processes that reduce residual tensile stresses, and monitoring and maintenance of coolant chemistry. The resistant materials are used for new and replacement components and include low-carbon grades of austenitic SS and weld metal, with a maximum carbon of 0.035 wt.% and a minimum ferrite of 7.5% in weld metal and cast austenitic stainless steel (CASS). Inconel 82 is the only commonly used nickel-base weld metal considered to be resistant to SCC; other nickel-alloys, such as Alloy 600 are evaluated on an individual basis. Special processes are used for existing, individual basis. Special processes are used for existing, new, and replacement components. These processes include solution heat treatment, heat sink welding, induction heating, and mechanical stress improvement.

The program delineated in NUREG-0313 and NRC GL 88-01 does not provide specific guidelines for controlling reactor water chemistry to mitigate IGSCC. Maintaining high water purity reduces susceptibility to SCC or IGSCC. The program description, and evaluation and technical basis of monitoring and maintaining reactor water chemistry are addressed through implementation of Section XI.M2.

The applicant was asked to confirm that AMP B.1.7 in the OCGS LRA will be revised to include this enhancement.

In its letter dated April 17, 2006 (ML061150320), the applicant committed to revise AMP B.1.7 in the OCGS LRA to include the enhancement identified in the program basis document, PBD-AMP-B.1.07, which states that for those components within the scope of the BWR stress corrosion cracking aging management program, all new and replacement SS materials will be low-carbon grades of SS with carbon content limited to 0.035 wt. % maximum and ferrite content limited to 7.5% minimum. **This is Audit Commitment 3.0.3.2.7-1.**

In reviewing this enhancement, the project team noted that the carbon content and ferrite content screening criteria, as stated in GL 88-01, are applicable to both new and replacement components while procuring and installing them during the life of a plant. Therefore, these criteria should already have been implemented at Oyster Creek. The applicant was asked to explain the reasons for this enhancement to an existing program, which should have included this screening criteria as part of the current licensing basis. In its response, the applicant stated that all replacements of piping components vulnerable to IGSCC during refueling outage 13R were performed in accordance with GL 88-01. However, the current documentation does not include the GL 88-01 commitments in the OCGS BWR stress corrosion cracking program; therefore, this enhancement to the program is necessary to update the plant documentation so that it will meet the recommendations in the September 2005 GALL Report.

On this basis, the project team found the enhancement to be acceptable since when the enhancement is implemented, OCGS AMP B.1.7, ?BWR Stress Corrosion Cracking," will be consistent with GALL AMP XI.M7.

3.0.3.2.7.5 Operating Experience

In the OCGS LRA, the applicant stated that, of the welds included in the scope of GL 88-01, Oyster Creek had 11 welds in service with indications of IGSCC. Nine were repaired with full structural overlays (four in core spray, four in recirculation and one in shutdown cooling). Two were in service without repair in the recirculation system since they were both stress improved before the inspections found IGSCC. Both of these welds in the recirculation system have recently been re-examined using the UT method and no IGSCC was identified. No new indications of IGSCC have been detected by inspection during the last six (6) outages.

The applicant also stated that Oyster Creek replaced the following piping material with IGSCC resistant material: 1) all isolation condenser large bore piping outside the drywell (from the drywell penetrations to the isolation condensers),including all new stress-improved welds; 2) all piping within the four (4) isolation condenser drywell penetrations and the two (2) RWCU system drywell penetrations, which contain welds that are not inspectable; and 3) the head cooling spray nozzle assembly 4 inch tee and flange of the reactor vent line. Additionally, all accessible/inspectable welds inside the drywell (except RWCU system) were stress improved.

Furthermore, as a result of the improved quality of water chemistry due to the implementation of HWC and NWCA, reductions in inspection frequency, which are permissible per BWRVIP-75, were implemented at Oyster Creek.

The applicant further stated that BWR stress corrosion cracking aging management program activities have detected flaw indications in reactor coolant pressure boundary piping prior to loss of intended functions of the components. These indications were evaluated and were repaired, as necessary, in accordance with ASME Section XI. As a result, Oyster Creek has no indications of IGSCC at this time.

The project team reviewed the operating experience information given in the PBD and found that, since GL 88-01 was issued, Oyster Creek has been performing ISI examinations on piping subject to the generic letter recommendations. During this period, Oyster Creek has implemented hydrogen water chemistry (HWC) and performed stress improvements as IGSCC mitigators. In addition, examination procedures have been improved and examination personnel have received training on the latest techniques for IGSCC detection. Oyster Creek personnel have gained years of experience in the detection and sizing of IGSCC. No new indications of IGSCC have been detected by inspection during the last six (6) outages.

The project team reviewed the operating experience provided in the OCGS LRA, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience, and discussions with the applicant's technical staff, the project team determined that the applicant’s BWR stress corrosion cracking program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.2.7.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the BWR stress corrosion cracking program in OCGS LRA, Appendix A, Section A.1.7 which states that the BWR stress corrosion cracking aging management program is an existing program based on NUREG-0313, and Nuclear

Regulatory Commission GL 88-01and its Supplement 1; NUREG-0313, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping;" GL 88-01, "NRC Position on Intergranular Stress Corrosion Cracking (IGSCC) in BWR Austenitic Stainless Steel Piping," and its Supplement 1; BWRVIP-75, "Technical Basis for Revisions to GL 88-01 Inspection Schedules;" and ASME Section XI. The scope of the BWR stress corrosion cracking aging management program includes reactor coolant pressure boundary components and piping four inches and larger nominal pipe size made of stainless steel and exposed to reactor coolant above 200ºF. The program includes (a) replacements and preventive measures to mitigate IGSCC, and (b) inspections to monitor IGSCC and its effects. Water chemistry is controlled through implementation of the recommendations of BWRVIP-130, ?BWR Vessel and Internals Project BWR Water Chemistry Guidelines."

The applicant committed to revise AMP B.1.7 (see Section 3.03.2.7.4, commitment 3.0.3.2.7-1) in the OCGS LRA to include the enhancement identified in the reconciliation document, which states that for those components within the scope of the BWR stress corrosion cracking aging management program, all new and replacement SS materials will be low-carbon grades of SS with carbon content limited to 0.035 wt. % maximum and ferrite content limited to 7.5% minimum. The applicant's license renewal commitment list and UFSAR update are to be revised to reflect this new commitment.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.7. Contingent upon the inclusion of commitment 3.0.3.2.7-1, the project team found that it was consistent with the GALL Report, and determined that it provided an adequate summary description of the program, as identified in the SRP-LR UFSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.2.7.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team determined that those portions of the program for which the applicant claims consistency with the GALL Report are consistent with the GALL Report. In addition, the project team reviewed the one exception stated in the OCGS LRA for this AMP, and concurred with the applicants decision to withdraw this exception based on reconciliation of the AMPs in the draft January 2005 version of the GALL Report with the approved September 2005 version of the GALL Report. The project team also reviewed the enhancement and its associated justifications, and determined that the AMP, with the enhancement, is adequate to manage the aging effects for which it is credited. The project team also reviewed the UFSAR Supplement for this AMP and, contingent upon the inclusion of Audit Commitment 3.0.3.2.7-1, the project team found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.8 BWR Penetrations (OCGS AMP B.1.8)

In the OCGS LRA, Appendix B, Section B.1.8, the applicant stated that OCGS AMP B.1.8, "BWR Penetrations," is an existing plant program that is consistent with GALL AMP XI.M8, "BWR Penetrations," with exceptions.

3.0.3.2.8.1 Program Description

In the OCGS LRA, the applicant stated that this program's activities incorporate the inspection and evaluation recommendations of BWRVIP-27-A, ?BWR Standby Liquid Control System/Core Plate Delta-P Inspection and Flaw Evaluation Guidelines," and BWRVIP-49-A, ?Instrument

Penetration Inspection and Flaw Evaluation Guidelines,? as well as the water chemistry recommendations of BWRVIP-130, ?BWR Vessel and Internals Project BWR Water Chemistry Guidelines," for the standby liquid control nozzle and instrument penetrations.

The applicant also stated that the program is implemented through station procedures that provide for mitigation of cracking through water chemistry, and monitoring for cracking through inservice inspection examinations. Penetration inspections are implemented through station procedures that are part of reactor internals inspection and incorporate the requirements of ASME Section XI.

3.0.3.2.8.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.8 is consistent with GALL AMP XI.M8, with exceptions.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.8, including the OCGS program basis document, PBD-AMP-B.1.08, ?BWR Penetrations," Rev. 0, 11/22/2005, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M8. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.8 and associated bases documents to determine their consistency with GALL AMP XI.M8.

The project team noted that OCGS has implemented the recommendations of BWRVIP-27-A and BWRVIP-49-A through the following inspection procedures: Exelon implementation procedures ER-AB-331, ?BWR RX Internals Management Program Activities," Rev. 3, and ER-AB-331-1001, ?BWR Internals," Rev. 0. These procedures are based on the ?ISI Program Plan" (OC-1, Rev. 1, 9/1/2004) and the ?Reactor Internals Program Plan" (OC-5, Rev. 0, 9/30/2005). Repairs and replacements are governed by procedure ER-AA-330-009, ?ASME Section XI Repair/Replacement Program," Rev. 3.

The project team verified that the OCGS reactor internals program plan, OC-5, includes the instrument penetrations and the standby liquid control nozzle, and implements the recommendations of BWRVIP–27-A and BWRVIP-49-A. Inspections are performed in accordance with the station ISI program (OC-1).

The project team also noted that repair and replacement activities, if needed, are performed in accordance with the recommendations of the appropriate BWRVIP repair/replacement guidelines. These are specified in implementation procedure ER-AB-331-1001 (Rev. 0).

The project team reviewed those portions of the BWR Penetrations program for which the applicant claims consistency with GALL AMP XI.M8 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's BWR penetrations program conforms to the recommended GALL AMP XI.M8, with the exceptions described below.

3.0.3.2.8.3 Exceptions to the GALL Report

In the OCGS LRA, the applicant stated the following exceptions to the GALL Report program elements:

Exception 1

Element: 2. Preventive Actions

Exception: NUREG-1801 indicates that water chemistry control is in accordance with BWRVIP-29 for water chemistry in BWRs. BWRVIP-29 references the 1996 revision of EPRI TR-103515, "BWR Water Chemistry Guidelines." The Oyster Creek water chemistry programs are based on BWRVIP-130, which is the 2004 revision of "BWR Water Chemistry Guidelines. For justification of exceptions to the water chemistry program see the Water Chemistry aging management program, B.1.2.

The GALL Report identified the following recommendations for the ?preventive actions” program element associated with the exception taken:

> *2. Preventive Actions:* Maintaining high water purity reduces susceptibility to SCC or IGSCC. Reactor coolant water chemistry is monitored and maintained in accordance with the guidelines in BWRVIP-29 (EPRI TR-103515). The program description and the evaluation and technical basis of monitoring and maintaining reactor water chemistry are presented in Chapter XI.M2.

The project team reviewed the OCGS Water Chemistry Program (AMP B.1.2) and concluded that the use of BWRVIP-130 is acceptable. The project team’s evaluation of OCGS AMP B.1.2 is discussed in Section 3.0.3.2.2 of this audit and review report. On this basis, the project team determined that the above exception is acceptable.

Exception 2

Element: 3. Parameters Monitored or Inspected

Exception: NUREG-1801 program XI.M9 references ASME Section XI, Table IWB 2500-1 (2001 edition, including the 2002 and 2003 Addenda). Oyster Creek ISI program is based on the 1995 (including 1996 Addenda) version of ASME Section XI. For justification of exceptions to the ISI program see the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program, B1.1.

The GALL Report identified the following recommendations for the ?Parameters Monitored or Inspected” program element associated with the exception taken:

> *3. Parameters Monitored or Inspected:* The program monitors the effects of SCC/IGSCC on the intended function of the component by detection and sizing of cracks by ISI in accordance with the guidelines of approved BWRVIP-49 or BWRVIP-27 and the recommendations of the ASME Code, Section XI, Table IWB 2500-1 (2001 Edition 6 including the 2002 and 2003 Addenda). An applicant may use the guidelines of BWRVIP-62 for inspection relief for vessel internal components with hydrogen water chemistry, provided that such relief is submitted under the provisions of 10 CFR 50.55a and approved by the staff.

In reviewing this exception, the project team recognized that, in accordance with note 5 to AMP XI.M9 in the GALL Report, ?An applicant may rely on a different version of the ASME Code, but should justify such use. An applicant may wish to refer to the SOC for an update of 10 CFR § 50.55a to justify use of a more recent edition of the Code.”

The project team also recognized that 10 CFR 50.55a is revised periodically to adopt, by reference, new editions and addenda of the ASME Code. For each successive 120-month (10 year) inspection interval, applicants are required to revise the nuclear plant’s ISI program to incorporate the requirements specified in the version of the ASME Code referenced in 10 CFR 50.55a 12 months prior to the start of the inspection interval.

At present, the applicant is committed to the 1995 version (including 1996 addenda) of the ASME Section XI Code during its fourth ten-year inspection interval, which is effective from October 15, 2002 through October 14, 2012, approved per 10CFR50.55a. The next 120-month inspection interval will incorporate the requirements specified in the version of the ASME Code referenced in 10 CFR 50.55a 12 months prior to the start of the inspection interval.

The current OCGS ISI program is based on the 1995 version (including 1996 addenda) of ASME Section XI, and the program will be updated in accordance with 10 CFR 50.55a after each 10 year interval to meet the GALL-recommended guidelines. On this basis, the project team determined that this exception is acceptable.

3.0.3.2.8.4 Enhancements

None.

3.0.3.2.8.5 Operating Experience

In the OCGS LRA, the applicant stated that OC is currently in its fourth ISI inspection interval. In the history of the Oyster Creek ISI program no evidence of instrument penetration or standby liquid control nozzle cracking has been found. This provides evidence that the water chemistry program has been effective in minimizing the effects of stress corrosion cracking in the instrument and standby liquid control penetrations.

The applicant also stated in the OCGS LRA that the same inspection and testing methodologies are used for the BWR penetrations as are used for other reactor internals. These processes have detected cracking in other vessel internals components, as described in the operating experience of the BWR vessel internals program, OCGS AMP B.1.9.

A review of Oyster Creek operating experience shows that cracking in these penetrations has not occurred. It is, therefore, evident that the BWR penetration program, in conjunction with the Water Chemistry Program, is effectively managing cracking in the vessel SBLC and instrument penetrations.

The project team reviewed the operating experience provided in the OCGS LRA, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience, and discussions with the applicant's technical staff, the project team determined that the applicant’s BWR penetrations program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.2.8.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the BWR penetrations program in OCGS LRA, Appendix A, Section A.1.8, which states that the BWR penetrations aging management program is an existing program that includes (a) inspection and flaw evaluation in conformance with the guidelines of staff-approved boiling water reactor vessel and internals project (BWRVIP)-49-A, ?Instrument Penetration Inspection and Flaw Evaluation Guidelines," and BWRVIP-27-A, ?BWR Standby Liquid Control System/Core Plate Delta-P Inspection and Flaw Evaluation Guidelines," documents, and (b) monitoring and control of reactor coolant water chemistry in accordance with industry-recognized guidelines of BWRVIP-130: ?BWR Vessel and Internals Project BWR Water Chemistry Guidelines," to ensure the long-term integrity and safe operation of boiling water reactor vessel internal components. The requirements of ASME Section XI will be implemented in accordance with 10 CFR 50.55(a).

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.8, found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.2.8.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report, are consistent with the GALL Report. In addition, the project team has reviewed the exceptions and their associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. The project team also reviewed the UFSAR Supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.9 BWR Vessel Internals (OCGS AMP B.1.9)

This AMP is assigned to the Office of Nuclear Reactor Regulation, Division of Engineering staff and will be addressed separately in Section 3.0.3.3 of the SER related to the OCGS LRA.

3.0.3.2.10 Bolting Integrity (OCGS AMP B.1.12)

In OCGS LRA, Appendix B, Section B.1.12, the applicant stated that OCGS AMP B.1.12, "Bolting Integrity," is an existing plant program that is consistent with GALL AMP XI.M18, "Bolting Integrity," with exceptions.

3.0.3.2.10.1 Program Description

The applicant stated, in the OCGS LRA, that this program provides for condition monitoring of pressure retaining bolted joints within the scope of license renewal. The Bolting Integrity Program incorporates NRC and industry recommendations delineated in NUREG-1339, ?Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants", EPRI TR-104213, ?Bolted Joint Maintenance & Applications Guide," and EPRI NP-5769, ?Degradation and Failure of Bolting in Nuclear Power Plants," as part of the comprehensive corporate component pressure retaining bolting program. The program manages the loss of bolting function, including loss of material, cracking, and loss of preload aging effects, by performing visual inspections for pressure retaining bolted joint leakage. Inspection of ASME Class 1, 2 and 3 components is conducted in accordance with ASME Section XI. Non-Class 1, 2 and 3 component inspections rely on detection of visible leakage during routine observations and equipment maintenance activities. Procurement controls and installation practices, defined in plant procedures, ensure that only approved lubricants and torque are applied. The activities are implemented through station procedures.

The applicant also stated that the A193 Gr. B7 bolting is commonly used in ASME XI, Class 1, 2, & 3 piping systems and components. A193 Gr. B7 is a chromium-molybdenum material that is generally not susceptible to stress corrosion cracking. The bolting is considered low strength bolting at Oyster Creek, and is used in applications that do not require high strength bolting. This is documented in NRC Safety Evaluation for ISI relief request R-15, which addresses leaking of bolted flanges dated October 3, 1996, stated that Oyster Creek has no high strength bolting, except for CRD System.

3.0.3.2.10.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.12 is consistent with GALL AMP XI.M18, with exceptions.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.12, including program basis document PBD-AMP B.1.12, ?Bolting Integrity," Revision 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M18. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.12 and associated bases documents to determine consistency with GALL AMP XI.M18.

The project team reviewed those portions of the Bolting Integrity Program for which the applicant claims consistency with GALL AMP XI.M18 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's Bolting Integrity Program conforms to the recommended GALL AMP XI.M18, with the exceptions described below.

3.0.3.2.10.3 Exceptions to the GALL Report

In the OCGS LRA, the applicant stated the following exception to the GALL Report program elements:

Elements: 1. Scope of Program
7. Corrective Actions

Exception: NUREG-1801 indicates that the program covers all bolting within the scope of license renewal including component support and structural bolting. The Oyster Creek Bolting Integrity Program does not address structural or component support bolting.

The GALL Report identified the following recommendations for the above program elements associated with the exception taken:

1. *Scope of Program*: This program covers bolting within the scope of license renewal, including: 1) safety-related bolting, 2) bolting for nuclear steam supply system (NSSS) component supports, 3) bolting for other pressure retaining components, including non-safety-related bolting, and 4) structural bolting (actual measured yield strength ³ 150 ksi). The aging management of reactor head closure studs is addressed by XI.M3, and is not included in this program. The staff's recommendations and guidelines for comprehensive bolting integrity programs that encompass all safety-related bolting are delineated in NUREG-1339, which include the criteria established in the 1995 edition through the 1996 addenda of ASME Code Section XI. The industry's technical basis for the program for safety-related bolting and guidelines for material selection and testing, bolting preload control, ISI, plant operation, and maintenance, and evaluation of the structural integrity of bolted joints, are outlined in EPRI NP-5769, with the exceptions noted in NUREG-1339. For other bolting, this information is set forth in EPRI TR-104213.

7. *Corrective Actions*: Replacement of ASME pressure retaining bolting is performed in accordance with appropriate requirements of Section XI of the ASME Code, as subject to the additional guidelines and recommendations of EPRI NP-5769. Replacement of other pressure retaining bolting (i.e., non-Class 1 bolting) and disposition of degraded structural bolting is performed in accordance with the guidelines and recommendations of EPRI TR-104213. Replacement of NSSS component support bolting is performed in accordance with EPRI NP-5769. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

The applicant stated in the OCGS LRA, that the Oyster Creek Bolting Integrity Program does not address structural or component support bolting. The aging management of structural bolting is addressed by the Structures Monitoring Program, B.1.31 and ASME Section XI, Subsection IWE, B.1.27, addresses Primary Containment pressure bolting. Aging management of ASME Section XI Class 1, 2, and 3 and Class MC support members is addressed by the ASME Section XI, Subsection IWF aging management program, B.1.28.

The project team reviewed this exception and found that structural or component support bolting aging effects will be adequately managed by the structures monitoring program, B1.31 and ASME Section XI, Subsection IWE, B.1.27. The project team's review of these AMPs are discussed in Sections 3.0.3.2.24, 3.0.3.2.22 and 3.0.3.2.26, respectively. On this basis, the project team found this exception acceptable.

3.0.3.2.10.4 Enhancements

In the program basis document, the applicant identified the following enhancement in order to meet the GALL Report program elements:

Elements: 1. Scope of the Program
2. Preventive Actions
7. Corrective Actions

Enhancement: Enhance site procedure to include reference to EPRI TR-104213, ?Bolted Joint Maintenance & Application Guide," December 1995.

The GALL Report identified the following recommendations for the above program elements associated with the enhancement:

> 1. *Scope of Program*: This program covers bolting within the scope of license renewal, including: 1) safety-related bolting, 2) bolting for nuclear steam supply system (NSSS) component supports, 3) bolting for other pressure retaining components, including non-safety-related bolting, and 4) structural bolting (actual measured yield strength ³ 150 ksi). The aging management of Reactor Head Closure Studs is addressed by XI.M3, and is not included in this program. The staff's recommendations and guidelines for comprehensive bolting integrity programs that encompass all safety-related bolting are delineated in NUREG-1339, which include the criteria established in the 1995 edition through the 1996 addenda of ASME Code Section XI. The industry's technical basis for the program for safety-related bolting and guidelines for material selection and testing, bolting preload control, ISI, plant operation, and maintenance, and evaluation of the structural integrity of bolted joints, are outlined in EPRI NP-5769, with the exceptions noted in NUREG-1339. For other bolting, this information is set forth in EPRI TR-104213.
>
> 2. *Preventive Actions*: Selection of bolting material and the use of lubricants and sealants is in accordance with the guidelines of EPRI NP-5769, and the additional recommendations of NUREG-1339, to prevent or mitigate degradation and failure of safety-related bolting. NUREG-1339 takes exception to certain items in EPRI NP-5769, and recommends additional measures with regard to them. Bolting replacement activities include proper torquing of the bolts and checking for uniformity of the gasket compression after assembly. Maintenance practices require the application of an appropriate preload, based on EPRI documents.
>
> 7. *Corrective Actions*: Replacement of ASME pressure retaining bolting is performed in accordance with appropriate requirements of Section XI of the ASME Code, as subject to the additional guidelines and recommendations of EPRI NP-5769. Replacement of other pressure retaining bolting (i.e., non-Class 1 bolting) and disposition of degraded structural bolting is performed in accordance with the guidelines and recommendations of EPRI TR-104213. Replacement of NSSS component support bolting is performed in accordance with EPRI NP-5769. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

The applicant stated, in the program basis document, that the Oyster Creek program addresses the guidance contained in EPRI TR-104213, ?Bolted Joint Maintenance & Applications Guide," however the report is not specifically cited as a reference in the Exelon corporate or stations' specific bolted joint inspection/repair procedures. Enhance site procedure to include reference to EPRI TR-104213, Bolted Joint Maintenance & Application Guide, December 1995. The project team noted that this enhancement is not identified in OCGS LRA B1.12. The applicant was asked to clarify this discrepancy.

In its letter dated April 17, 2006 (ML061150320), the applicant committed to revise the Bolting Integrity Program (B.1.12) in the OCGS LRA to include the enhancement identified in the program basis document, which states that the site procedure will be enhanced to include reference to EPRI TR-104213, ?Bolted Joint Maintenance & Application Guide," December 1995. **This is Audit Commitment 3.0.3.2.10-1.**

The project team reviewed the EPRI TR-104213, 1995 edition and found it to be an acceptable revision of the original EPRI TR-104213. On this basis, the project team found this enhancement acceptable since when enhancement is implemented, OCGS AMP B.1.12, "Bolting Integrity," will be consistent with GALL AMP XI.M18 and will provide additional assurance that the effects of aging will be adequately managed.

3.0.3.2.10.5 Operating Experience

The applicant stated, in the OCGS program basis document, that a review of plant operating experience at Oyster Creek shows that loss of bolting function has occurred in a few isolated cases however in all cases the existing bolting integrity aging management program existing inspections and testing methodology have discovered that deficiency and corrective actions were taken prior to loss of system or component intended function.

Operating experience, both internal and external, is used in two ways at Oyster Creek to enhance plant programs, prevent repeat events, and prevent events that have occurred at other plants from occurring at Oyster Creek. The first way in which operating experience is used is through the Oyster Creek operating experience process. The operating experience process screens, evaluates, and acts on operating experience documents and information to prevent or mitigate the consequences of similar events. The second way is through the process for managing programs. This process requires the review of program related operating experience by the program owner.

The effective use of the corrective action program has identified torquing issues with plant equipment and identified improvement was needed. A CAP 02004-2340 requested a review of the existing Exelon Procedures and EPRI guidelines to incorporate best practices from recognized experts. Corrective actions included procedure changes and training to assure proper torquing requirements are included in maintenance work packages. This example provides objective evidence that industry experience is considered and provided improvement to the Bolting Integrity aging management program.

Oyster Creek has experienced isolated cases of loss of bolting function attributed to loss of material. Review of operating history has not identified any cracking of stainless steel bolting. Reactor coolant pressure boundary leakage due to boric acid induced degradation is not applicable since the station is a BWR. In all cases, the existing inspection and testing methodologies have discovered the deficiencies and corrective actions were implemented prior to loss of system or component intended functions. This provides objective evidence that loss of bolting function will be detected prior to loss of intended function and adequate corrective action is taken to resolve issues.

A review of Corrective Action Program (CAP) documents for Oyster Creek bolting indicates that they have been effective in identifying degradations and taking corrective action as necessary. Examples of discrepancies included CAP 02001-0960, where flange bolts on a blind flange were found to lack full nut engagement by approximately two threads. The condition was corrected. This provides objective evidence that deficiencies are identified within the Bolting Integrity AMP and are entered into the 10 CFR Part 50, Appendix B, corrective action process and actions are taken to resolve issues.

The project team reviewed the operating experience provided in the OCGS LRA, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant's Bolting Integrity Program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.2.10.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the Bolting Integrity Program in OCGS LRA, Appendix A, Section A.1.12, which states that the Bolting Integrity Program is an existing program that incorporates industry recommendations of EPRI NP-5769, ?Degradation and Failure of Bolting in Nuclear Power Plants," and includes periodic visual inspections of closure bolting for loss of bolting function. Inspection of Class 1, 2, and 3 components is conducted in accordance with ASME Section XI. The requirements of ASME Section XI will be implemented in accordance with 10 CFR 50.55(a). Program activities address the guidance contained in EPRI TR-104213, ?Bolted Joint Maintenance and Applications Guide". Non-ASME Class 1, 2 and 3 bolted joint inspections rely on detection of visible leakage during maintenance or routine observation. The Bolting Integrity Program does not address primary containment pressure retaining, structural and component support bolting. Primary containment pressure retaining bolting are addressed by ASME Section XI, Subsection IWE, A.1.27. The structures monitoring program, B.1.31 addresses the aging management of structural bolting. The ASME Section XI, Subsection IWF program, B.1.28, addresses aging management of ASME Section XI Class 1, 2, and 3 and Class MC support members.

In its letter dated April 17, 2006 (ML061150320), the applicant committed to revise the Bolting Integrity Program (B.1.12) in the OCGS LRA to include the enhancement identified in the program basis document, which states that the site procedure will be enhanced to include reference to EPRI TR-104213, ?Bolted Joint Maintenance & Application Guide," December 1995. This is Audit Commitment 3.0.3.2.10-1. The applicant's license renewal commitment list and UFSAR supplement are to be revised to reflect this new commitment.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.12. Contingent upon the inclusion of Audit Commitment 3.0.3.2.10-1, the project team found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.2.10.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report, are consistent with the GALL Report. In addition, the project team has reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. Also, the project team has reviewed the enhancements and determined that the implementation of the enhancements prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The project team also reviewed the UFSAR Supplement for this AMP and, contingent upon the inclusion of Audit Commitment 3.0.3.2.10-1, found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.11 Open-Cycle Cooling Water System (OCGS AMP B.1.13)

In OCGS LRA, Appendix B, Section B.1.13, the applicant stated that OCGS AMP B.1.13, "Open-Cycle Cooling Water System," is an existing plant program that is consistent with GALL AMP XI.M20, "Open-Cycle Cooling Water System," with enhancements.

3.0.3.2.11.1 Program Description

In the OCGS LRA, the applicant stated that this program is an existing program that manages aging of piping, piping components, piping elements and heat exchangers that are included in the scope of license renewal for loss of material and reduction of heat transfer, and are exposed to raw water - salt water at Oyster Creek. Program activities include (a) surveillance and control of biofouling (including biocide injection), (b) verification of heat transfer capabilities for components cooled by the service water and emergency service water systems, (c) inspection and maintenance activities, (d) walkdown inspections, and (e) review of maintenance, operating and training practices and procedures. Inspections may include visual, ultrasonic, and eddy current testing (ECT) methods. The OCCWS program is based on the recommendations of NRC GL 89-13.

The applicant also stated that its service water (SW) and emergency service water (ESW) systems are performance tested for acceptable flow rates, operating temperatures and operating pressures. Volumetric (UT) inspections are performed at various aboveground locations of the SW and ESW piping, including inspections performed outside at the intake structure. Results of the inspections are documented and continually analyzed to determine maximum expected corrosion rates and susceptible locations for future inspections. The aboveground inspection locations are representative of the same internal coatings, environments and aging effects present in the buried sections of the ESW and SW system piping. Therefore the inspection program adequately monitors the conditions of the ESW and SW system internal piping, including the buried piping.

The applicant further stated that volumetric inspections of aboveground ESW and SW piping that is original to the plant design are performed at a minimum of 10 locations every 2 years, based on the maximum anticipated corrosion rates determined from past inspections and analyses. The results of the volumetric inspections are trended and pipe replacement is scheduled prior to predicted failure. Predicting the failure based on corrosion rates, current wall thickness, environment, and scheduling replacement of the pipe is a mitigative action to prevent leaks. For piping that has been replaced, volumetric inspections will be performed at a minimum of 4 aboveground locations every 4 years, based on the observed and anticipated performance of the new pipe. The scope of these inspections will be evaluated to include additional inspection locations as new piping is replaced in the plant.

3.0.3.2.11.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.13 is consistent with GALL AMP XI.M20, with enhancements.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.13, including program basis document PBD-AMP-B.1.13, ?Open Cycle Cooling Water System," Rev. 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M20. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.13 and associated bases documents to determine their consistency with GALL AMP XI.M20.

The project team reviewed OCGS procedure EE-AA-340, Rev. 2, ?GL 89-13 Program Implementing Procedure," since the aging management program relies on implementation of the recommendations of the Nuclear Regulatory Commission GL 89-13 to assure that the effects of aging on the open-cycle cooling water (OCCW) (or service water) system will be managed for the extended period of operation. The project team also reviewed topical report TR 140, Rev. 2, ?Emergency Service Water and Service Water System Piping Plan," specification SP 1302-12-261, Revs. 7 and 8a, ?Safety-related Specification for Pipe Integrity Inspection Program," and TDR-829, Rev. 4, ?Inspection History of the OCNGS Pipe Integrity Program (Pipe Integrity Inspection Program)," to determine consistency with the GALL AMP XI.M20.

The project team reviewed those portions of the open-cycle cooling water system program for which the applicant claims consistency with GALL AMP XI.M20 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's open-cycle cooling water system program conforms to the recommended GALL AMP XI.M20, with the enhancements described below.

3.0.3.2.11.3 Exceptions to the GALL Report

None.

3.0.3.2.11.4 Enhancements

In the OCGS LRA, the applicant identified the following enhancements in order to meet the GALL Report program elements:

Enhancement 1

Elements:	1. Scope of Program 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring and Trending
Enhancement:	The open-cycle cooling water aging management program will be enhanced to include volumetric inspections, for piping that has been replaced, at a minimum of 4 aboveground locations every 4 years based on the observed and anticipated performance of the new pipe.

The GALL Report identified the following recommendations for the ?scope of program," ?parameters monitored or inspected," ?detection of aging effects," and ?monitoring and trending" program elements associated with the enhancement:

> 1. *Scope of Program*: The program addresses the aging effects of material loss and fouling due to micro- or macro-organisms and various corrosion mechanisms. ... The guidelines of NRC GL 89-13 include ... (c) routine inspection and a maintenance program to ensure that corrosion, erosion, protective coating failure, silting, and biofouling cannot degrade the performance of safety-related systems serviced by OCCW; ...

3. *Parameters Monitored or Inspected*: Cleanliness and material integrity of piping, components, heat exchangers, elastomers and their internal linings or coatings (when applicable) that are part of the OCCW system or that are cooled by the OCCW system are periodically inspected, monitored, or tested to ensure heat transfer capabilities. The program ensures (a) removal of accumulations of biofouling agents, corrosion products, and silt, and (b) detection of defective protective coatings and corroded OCCW system piping and components that could adversely affect performance of their intended safety functions

4. *Detection of Aging Effects*: Visual inspections are typically performed; however, nondestructive testing, such as ultrasonic testing, eddy current testing, and heat transfer capability testing are effective methods to measure surface condition and the extent of wall thinning associated with the service water system piping and components, when determined necessary.

5. *Monitoring and Trending*: Inspection scope, method (e.g., visual or NDE), and testing frequencies are in accordance with the utility commitments under NRC GL 89-13. ... Inspections or nondestructive testing will determine the extent of biofouling, the condition of the surface coating, the magnitude of localized pitting, and the amount of MIC, if applicable.

In reviewing this enhancement, the project team noted that volumetric inspections of aboveground ESW and SW piping that is original to the plant design are performed at a minimum of 10 locations every 2 years based on the maximum anticipated corrosion rates determined from past inspections and analyses. The stated enhancement will add a minimum of 4 UT inspections every 4 years on aboveground piping that has been replaced with the same coatings and materials as new buried ESW and SW piping. Since aboveground and buried piping are subject to the same internal environments and failure mechanisms, the volumetric inspections of aboveground piping bound the buried portions of piping. During the audit, the applicant confirmed that the inspection locations for new piping are in addition to the minimum of 10 locations for the original aboveground ESW and SW piping. The applicant also stated that the periodicity of the testing and inspections are based on previous findings and, if testing and inspections need to be more frequent, or the scope needs to be increased, then the program allows for this adjustment.

The project team determined that the above enhancement will provide an adequate method of inspecting piping that has been replaced, and is consistent with the recommendations in the GALL Report. The inspection sample population and frequency are adequate since, based on previous findings, the applicant’s program allows for adjustment of the population and frequency, as needed.

On this basis, the project team found this enhancement acceptable since when the enhancement is implemented, OCGS AMP B.1.13, "Open-Cycle Cooling Water System," will be consistent with GALL AMP XI.M20, and will provide additional assurance that the effects of aging will be adequately managed.

<u>Enhancement 2</u>

Elements:
1. Scope of Program
3. Parameters Monitored or Inspected
4. Detection of Aging Effects

5. Monitoring and Trending

Enhancement: The open-cycle cooling water aging management program will be enhanced to include specificity on inspection of heat exchangers for loss of material due to general, pitting, crevice, galvanic and MIC in the RBCCW, TBCCW and Containment Spray preventative maintenance tasks.

The GALL Report identified the following recommendation for the ?scope of program", ?parameters monitored or inspected," ?detection of aging effects," and ?monitoring and trending" program elements associated with the enhancement:

1. *Scope of Program*: The program addresses the aging effects of material loss and fouling due to micro- or macro-organisms and various corrosion mechanisms. Because the characteristics of the service water system may be specific to each facility, the OCCW system is defined as a system or systems that transfer heat from safety-related systems, structures, and components (SSC) to the ultimate heat sink (UHS). ... The guidelines of NRC GL 89-13 include (a) surveillance and control of biofouling; (b) a test program to verify heat transfer capabilities; (c) routine inspection and a maintenance program to ensure that corrosion, erosion, protective coating failure, silting, and biofouling cannot degrade the performance of safety-related systems serviced by OCCW; (d) a system walk down inspection to ensure compliance with the licensing basis, and (e) a review of maintenance, operating, and training practices and procedures.

3. *Parameters Monitored or Inspected*: Cleanliness and material integrity of piping, components, heat exchangers, elastomers and their internal linings or coatings (when applicable) that are part of the OCCW system or that are cooled by the OCCW system are periodically inspected, monitored, or tested to ensure heat transfer capabilities. The program ensures (a) removal of accumulations of biofouling agents, corrosion products, and silt, and (b) detection of defective protective coatings and corroded OCCW system piping and components that could adversely affect performance of their intended safety functions

4. *Detection of Aging Effects*: Inspections for biofouling, damaged coatings, and degraded material condition are conducted. Visual inspections are typically performed; however, nondestructive testing, such as ultrasonic testing, eddy current testing, and heat transfer capability testing are effective methods to measure surface condition and the extent of wall thinning associated with the service water system piping and components, when determined necessary.

5. *Monitoring and Trending*: Inspection scope, method (e.g., visual or NDE), and testing frequencies are in accordance with the utility commitments under NRC GL 89-13. Testing and inspections are done annually and during refueling outages. Inspections or nondestructive testing will determine the extent of biofouling, the condition of the surface coating, the magnitude of localized pitting, and the amount of MIC, if applicable. Heat transfer testing results are documented in plant test procedures and are trended and reviewed by the appropriate group.

In reviewing this enhancement, the project team noted that the RBCCW and containment spray heat exchangers are included in the scope of license renewal for the intended function of pressure boundary and heat transfer. The TBCCW heat exchangers are included for a leakage boundary function only. The current GL 89-13 program at Oyster Creek only includes the ESW system and containment spray heat exchangers. This commitment will not change as a result of this enhancement, however, attributes of the GL 89-13 guidance will be implemented for the SW system, RBCCW system, and TBCCW system heat exchangers as part of the OCGS open cycle cooling water aging management program (AMP B.1.13). Upon implementation of this enhancement, the OCGS AMP B.1.13 will be consistent with the recommendations in AMP XI.M20 in the GALL Report.

On this basis, the project team found this enhancement acceptable since when the enhancement is implemented, OCGS AMP B.1.13, "Open-Cycle Cooling Water System," will be consistent with GALL AMP XI.M20, and will provide additional assurance that the effects of aging will be adequately managed.

3.0.3.2.11.5 Operating Experience

In the OCGS LRA, the applicant stated that Oyster Creek has reviewed both plant-specific operating experience relating to the OCCWS aging management program. Inspections implementing the guidance of GL 89-13 have identified deterioration, degradation and loss of material from inside the pipe.

Oyster Creek has performed evaluations to identify the buried piping with high risk of developing leaks and high consequences, should leaks occur. Piping replacements are scheduled based on the risk priority, and the monitoring and inspection program assures that the piping maintains adequate wall thickness with margin prior to replacement.

The methodology for determining corrosion rates and projected service life was revised in 2002 based on analysis of station operating experience and previous inspection results. Additionally, in 2004 fifty percent of the buried ESW and ten percent of the buried SW piping was replaced with new pipe and an improved coating system. A plan is in place to replace the other fifty percent of the buried ESW piping prior to 2007.

After identifying and reviewing several ESW pipe leaks and wall thinning events, a common failure mechanism (local wall thinning due to salt-water corrosion) was identified. The results were entered into the corrective action process, and an operability evaluation was performed in 2003. The operability evaluation also included an evaluation of the effect of the failure mechanism on the SSC safety functions including functional thresholds and methods for detection of leaks for each of the safety functions. Additionally, the corrective action process problem resolution response included the development of an inspection plan, ?Topical Report 140 – ESW and Service Water System Plan." Some of the plan's goals are to prioritize modifications and inspections based on risk and consequence of a leak, modify piping segments that pose a high risk and consequence and cannot be reasonably inspected, modify piping to allow system flexibility for future repairs and inspect piping to ensure disposition/repair prior to failure. The plan captures existing analysis, past action and future action for ESW and SW pipe.

The OCCWS aging management program is continually adjusted to account for station experience and research. As additional operating experience is obtained, lessons learned will be used to adjust this program as needed. The project team reviewed topical report TR 140, Rev. 2, ?Emergency Service Water and Service Water System Piping Plan," specification SP 1302-12-261, Revs. 7 and 8a, ?Safety-related Specification for Pipe Integrity Inspection

Program," and TDR-829, Rev. 4, ?Inspection History of the OCNGS Pipe Integrity Program (Pipe Integrity Inspection Program)," and concluded that it verifies the effectiveness of the applicant's aging management program in its use of station operating experience to assess program performance, implement program adjustments, and to plan future actions.

The project team reviewed the operating experience provided in the OCGS LRA, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience, and discussions with the applicant's technical staff, the project team determined that the applicant's open-cycle cooling water system program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.2.11.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the open-cycle cooling water system program in OCGS LRA, Appendix A, Section A.1.13, which states that the open-cycle cooling water system aging management program is an existing program that manages aging of piping, piping components, piping elements and heat exchangers that are included in the scope of license renewal for loss of material and reduction of heat transfer and are exposed to raw water – salt water at Oyster Creek. Program activities include (a) surveillance and control of biofouling (including biocide injection), (b) verification of heat transfer capabilities for components cooled by the Service Water and Emergency Service Water systems, (c) inspection and maintenance activities, (d) walkdown inspections, and (e) review of maintenance, operating, and training practices and procedures. Inspections may include visual, UT, and eddy current testing (ECT) methods. The program will be enhanced to include specificity on inspection of heat exchangers for loss of material due to general, pitting, crevice, galvanic and MIC in the RBCCW, TBCCW and containment spray preventative maintenance tasks. Additionally, the program will be enhanced to include volumetric inspections, for piping that has been replaced, at a minimum of 4 aboveground locations every 4 years, based on the observed and anticipated performance of the new pipe. Enhancements to the program will be implemented prior to entering the period of extended operation. The OCCWS aging management program is based on the recommendations of NRC GL 89-13.

The project team also reviewed the applicant's license renewal commitment list in Appendix A of the OCGS LRA, and confirmed that the enhancements to this program are identified and will be implemented prior to the period of extended operation as item 13 of the commitments.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.13, found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.2.11.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report, are consistent with the GALL Report. Also, the project team has reviewed the enhancements and determined that the implementation of the enhancements prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The project team also reviewed the UFSAR Supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.12 Close-Cycle Cooling Water System (OCGS AMP B.1.14)

In the OCGS LRA, Appendix B, Section B.1.14, the applicant stated that OCGS AMP B.1.14, "Closed-Cycle Cooling Water System," is an existing plant program that is consistent with GALL AMP XI.M21, "Closed-Cycle Cooling Water System," with an exception.

3.0.3.2.12.1 Program Description

In the OCGS LRA, the applicant stated that this program manages aging of piping, piping components, piping elements and heat exchangers that are included in the scope of license renewal for loss of material and reduction of heat transfer and are exposed to a closed cooling water environment at Oyster Creek. The program provides for preventive, performance monitoring and condition monitoring activities that are implemented through station procedures. Preventive activities include measures to maintain water purity and the addition of corrosion inhibitors to minimize corrosion based on EPRI TR-1007820, "Closed Cooling Water Chemistry Guidelines."

The applicant also stated that performance monitoring provides indications of degradation in closed-cycle cooling water systems, with plant operating conditions providing indications of degradation in normally operating systems. In addition, station maintenance inspections and NDE provide condition monitoring of heat exchangers exposed to closed-cycle cooling water environments.

3.0.3.2.12.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.14 is consistent with GALL AMP XI.M21, with an exception.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.14, including program basis document PBD-AMP-B.1.14, ?Closed Cycle Cooling Water Systems," Rev. 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M21. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.14 and associated bases documents to determine their consistency with GALL AMP XI.M21.

The project team also reviewed, in part, several of the corporate and station procedures used for chemistry control activities and surveillance testing, including CY-AA-120-400, ?Closed Cooling Water Chemistry Strategic Plan," Rev. 8; CY-AA-120-110, ?Chemistry Limits and Frequencies," Rev. 0; and 309.1.1, ?Turbine Building Closed Cooling Water Routine Evolutions," Rev. 1, to assure that aging effects attributable to closed-cycle cooling water systems will be adequately managed during the period of extended operation, and to determine consistency with GALL AMP XI.M21.

The project team reviewed those portions of the Closed-Cycle Cooling Water System program for which the applicant claims consistency with GALL AMP XI.M21 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's program conforms to the recommended GALL AMP XI.M21, with the exception described below.

3.0.3.2.12.3 Exceptions to the GALL Report

In the OCGS LRA, the applicant stated the following exception to the GALL Report program elements:

Elements:
2. Preventive Actions
3. Parameters Monitored or Inspected
4. Detection of Aging Effects
5. Monitoring and Trending
6. Acceptance Criteria

Exception: NUREG 1801 refers to EPRI TR-107396 Closed Cooling Water Chemistry Guidelines 1997 Revision. Oyster Creek implements the guidance provided in EPRI 1007820 "Closed Cooling Water Chemistry Guideline, Revision 1" which is the 2004 Revision to TR-107396. EPRI periodically updates industry water chemistry guidelines, as new information becomes available. Oyster Creek has reviewed EPRI 1007820 and has determined that the most significant difference is that the new revision provides more prescriptive guidance and has a more conservative monitoring approach. EPRI 1007820 meets the same [recommendations] of EPRI TR-107396 for maintaining conditions to minimize corrosion and microbiological growth in closed cooling water systems for effectively mitigating many aging effects.

The GALL Report identified the following recommendations for the ?preventive actions," ?parameters monitored or inspected," ?detection of aging effects," ?monitoring and trending," and ?acceptance criteria" program elements associated with the exception taken:

2. *Preventive Actions:* The program relies on the use of appropriate materials, lining, or coating to protect the underlying metal surfaces and maintain system corrosion inhibitor concentrations within the specified limits of EPRI TR-107396 to minimize corrosion and SCC.

3. *Parameters Monitored or Inspected*: The aging management program monitors the effects of corrosion and SCC by testing and inspection in accordance with guidance in EPRI TR-107396 to evaluate system and component condition.

4. *Detection of Aging Effects:* Control of water chemistry does not preclude corrosion or SCC at locations of stagnant flow conditions or crevices. Degradation of a component due to corrosion or SCC would result in degradation of system or component performance. The extent and schedule of inspections and testing should assure detection of corrosion or SCC before the loss of the intended function of the component. (NUREG 1801 refers to EPRI TR-1007820 for control of water chemistry).

5. *Monitoring and Trending*: In accordance with EPRI TR-107396, internal visual inspections and performance/functional tests are to be performed periodically to demonstrate system operability and confirm the effectiveness of the program.

6. *Acceptance Criteria*: Corrosion inhibitor concentrations are maintained within the limits specified in the EPRI water chemistry guidelines for CCCW. (NUREG 1801 refers to EPRI TR-1007820 for control of water chemistry).

As part of the audit, the project team interviewed the applicant's technical staff to discuss technical issues related to this exception. During the interview, the applicant described its review and evaluation of the differences between EPRI TR-107396, ?Closed Cooling Water Chemistry Guidelines," the 1997 revision of the guidelines referred to in NUREG-1801, and EPRI TR-1007820, ?Closed Cooling Water Chemistry Guideline, Revision 1," which is the 2004 revision implemented by Oyster Creek. In addition, in its response to an audit question, the applicant stated that the most significant difference is that EPRI TR-1007820 provides more prescriptive guidance and has a more conservative monitoring approach. The applicant further stated that EPRI TR-1007820 meets the same recommendations of EPRI TR-107396 for maintaining conditions to minimize corrosion and microbiological growth in closed cooling water systems for effectively mitigating many aging effects. In addition, the applicant stated that it had contacted the author of EPRI TR-107396 and EPRI TR-1007820, Anthony Selby, to confirm that the new guidance that was provided in TR-1007820 was not contrary to the guidance in TR-107396.

The project team reviewed EPRI TR-1007820, ?Closed Cooling Water Chemistry Guideline, Revision 1," and EPRI TR-107396 (Revision 0) and confirmed the applicant's assessment that the new revision provides more prescriptive guidance, has a more conservative monitoring approach, and meets the same requirements for maintaining conditions to minimize corrosion and microbiological growth in closed cooling water systems for effectively mitigating many aging effects. On this basis, the project team found this exception acceptable.

3.0.3.2.12.4 Enhancements

None.

3.0.3.2.12.5 Operating Experience

In the OCGS LRA, the applicant stated that it has not experienced a loss of intended function failure of components due to corrosion product buildup or through-wall loss of material for components within the scope of license renewal that are subject to closed-cycle cooling water system activities. Additionally, industry experience demonstrates that the use of corrosion inhibitors in closed-cycle cooling water systems that are monitored and maintained is effective in mitigating loss of material and buildup of deposits. Events have occurred where buildup of deposits resulted in degraded heat transfer in heat exchangers; however, this has occurred on the tube side of the heat exchangers. The tube side of the heat exchangers are exposed to raw water – salt water and are managed by the open cycle cooling water program.

In the OCGS LRA, the applicant stated that in 2002 they increased their desired molybdate range in all of the closed-cycle cooling water systems from 50-125 ppm to 200-1000 ppm. This enabled the applicant to align with industry best practices. In 2004, the pH in the TBCCW system decreased outside the Action Level 1 range for pH. A caustic was added that returned pH back to specifications within the acceptable time period for correcting an Action Level 1 CCW limit.

In addition to mitigating loss of material and buildup of deposits by maintaining water chemistry, the applicant monitors the RBCCW, TBCCW and EDGCW for microbiological growth (total bacteria colonies) in accordance with EPRI TR-1007820, "Closed Cooling Water Chemistry Guidelines." To date, there have been no adverse trends associated with microbiological growth in closed-cycle cooling water systems.

In its design basis document for the CCCW system (PDB B.1.14), the applicant stated that operating experience, both internal and external, is used to enhance plant programs, prevent repeat events, and prevent events that have occurred at other plants from occurring at Oyster Creek. Through its operating experience review process the applicant screens, evaluates, and acts on operating experience documents and information to prevent or mitigate the consequences of similar events. In addition, the applicant stated that its process for managing programs requires the review of program related operating experience by the program owner. Both of these processes review operating experience from both external and internal (also referred to as in-house) sources. External operating experience may include such things as INPO documents (e.g., SOERs, SERs, SENs, etc.), NRC documents (e.g., GLs, LERs, INs, etc.), General Electric documents (e.g., RCSILs, SILs, TILs, etc.), and other documents (e.g., 10CFR Part 21 Reports, NERs, etc.). Internal operating experience may include such things as event investigations, trending reports, and lessons learned from in-house events as captured in program notebooks, self-assessments, and in the 10 CFR Part 50, Appendix B corrective action process. Issues and events, whether external or plant-specific, that are potentially significant to the closed cycle cooling water program at OCGS are evaluated. The closed-cycle cooling water program is augmented, as appropriate, if these evaluations show that program changes are needed to enhance program effectiveness.

The corrective actions program ensures that the conditions adverse to quality are promptly corrected. If the deficiency is assessed to be significantly adverse to quality, the cause of the condition is determined and a corrective action plan is developed to preclude repetition. The applicant stated, in the OCGS LRA, that OCGS has not experienced a loss of intended function failure of components due to corrosion product buildup or through-wall loss of material for components within the scope of license renewal that are subject to closed-cycle cooling water system activities. The applicant further stated that problems that have been identified would not have a significant impact on the safe operation of the plant and, to date, there have been no adverse trends associated with microbiological growth in closed cycle cooling water systems

In the OCGS LRA and the program basis document, the applicant stated that by improving the closed-cycle cooling water chemistry monitoring parameters, returning out of range parameters within acceptable limits in a timely manner and monitoring for microbiological growth, the applicant has been effective in managing components for loss of material and reduction of heat transfer that are exposed to a closed cooling water environment. Additionally, the Closed-Cycle Cooling Water System aging management program is continually adjusted to account for station experience and research. As additional operating experience is obtained, lessons learned are used to adjust this program as needed.

The project team reviewed the operating experience provided in the OCGS LRA, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience, and discussions with the applicant's technical staff, the project team determined that the applicant’s Closed-Cycle Cooling Water System program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.2.12.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the Closed-Cycle Cooling Water System program in OCGS LRA, Appendix A, Section A.1.14, which states that the Closed-Cycle Cooling Water System program is an existing program that manages aging of piping, piping components, piping elements and heat exchangers that are included in the scope of license renewal for loss of material and reduction of heat transfer and are exposed to a closed cooling water environment at Oyster Creek. The program provides for preventive, performance monitoring and condition monitoring activities that are implemented through station procedures. Preventive activities include measures to maintain water purity and the addition of corrosion inhibitors to minimize corrosion based on EPRI TR-1007820, "Closed Cooling Water Chemistry Guidelines." Performance monitoring provides indications of degradation in closed-cycle cooling water systems, with plant operating conditions providing indications of degradation in normally operating systems. In addition, station maintenance inspections and NDE provide condition monitoring of heat exchangers exposed to closed-cycle cooling water environments.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.14, found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.2.12.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report, are consistent with the GALL Report. In addition, the project team has reviewed the exception and the associated justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. The project team also reviewed the UFSAR Supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.13 Boraflex Rack Management Program (OCGS AMP B.1.15)

In OCGS LRA, Appendix B, Section B.1.15, the applicant stated that OCGS AMP B.1.15, "Boraflex Rack Management Program," is an existing plant program that is consistent with GALL AMP XI.M22, "Boraflex Monitoring," with an exception.

3.0.3.2.13.1 Program Description

The applicant stated, in the OCGS LRA, that this program is based on manufacturer's recommendations, industry guidelines developed in response to NRC GL 96-04, and plant specific operating experience. The program employs a defense in depth strategy to detect and take appropriate actions for degraded Boraflex to ensure the 5% subcriticality margin is maintained. The program consists of condition monitoring activities that include periodic inspection of sample Boraflex coupons, in-situ testing of boron areal density using BADGER device, monitoring dissolved silica in the spent fuel storage pool and trending the results using EPRI RACKLIFE predictive code. The RACKLIFE predictive model is updated periodically and validated through the BADGER boron areal density tests. The BADGER test is conducted every 3 years.

3.0.3.2.13.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.15 is consistent with GALL AMP XI.M22, with an exception.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.15, including program basis document PBD-AMP B.1.15, ?Boraflex Rack Management Program," Revision 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M22. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.15 and associated bases documents to determine consistency with GALL AMP XI.M22.

The project team reviewed those portions of the boraflex rack management program for which the applicant claims consistency with GALL AMP XI.M22 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's boraflex rack management program conforms to the recommended GALL AMP XI.M22, with the exceptions noted below.

3.0.3.2.13.3 Exceptions to the GALL Report

The applicant stated, in the OCGS LRA, that the exception to the GALL Report program elements is as follows:

Element: 2. Preventive Actions

Exception: Blackness test is not performed. The test is replaced with boron areal density measurements using the BADGER device, which gives a better indication of Boraflex effectiveness to perform its intended function.

The GALL Report identifies the following recommendation for the ?preventive actions" program element associated with the exception taken:

> 2. *Preventive Actions*: For Boraflex panels, monitoring silica levels in the storage pool water, measuring gap formation by blackness testing, periodically measuring boron areal density.

The applicant stated, in the OCGS LRA, that blackness test is not performed. The test is replaced with boron areal density measurements using the BADGER device, which gives a better indication of Boraflex effectiveness to perform its intended function. The project team questioned why area density measurement is equal to or better than blackness tests. The OCGS replied that blackness testing only provides information regarding the presence of neutron absorber material. Blackness testing will provide information regarding gaps or missing sections in the Boraflex panel. However, areal density testing using BADGER provides a direct measurement of in-rack performance of Boraflex panels. The areal density test measures gaps, erosion and general thinning of the scanned Boraflex panel. Blackness testing gives only an indication whether neutron absorber is present or not in a boraflex panel whereas BADGER test provides a quantitative measurement of Boron-10 areal density of neutron absorber in the rack.

The project team reviewed this exception and determined that, because the Areal Density test is more quantitative than the blackness test, this exception was acceptable.

3.0.3.2.13.4 Enhancements

None.

3.0.3.2.13.5 Operating Experience

The applicant stated, in the OCGS LRA, that the Oyster Creek boraflex rack management program has been in effect since 1986 when the new high density poison racks were installed in the spent fuel storage pool. The program initially consisted of testing of sample coupons maintained in the spent fuel pool and upgraded later to include in-situ testing of boron areal density using the BADGER device. To date two BADGER tests were conducted, one in 1997, and the second in 2001. Both tests identified the presence of degradations similar to those experienced in the industry, including some areas of local dissolution of boron carbide, and formation of shrinkage induced gaps. However, both tests show that the average areal density of Boraflex is well in excess of the minimum certified areal density by the manufacturer. The in-situ areal density test using the BADGER device has proved effective in identifying unacceptable degradation prior to a loss of an intended function. Corrective actions are initiated if the test results find that the 5% subcriticality margin cannot be maintained because of current or projected future Boraflex degradation.

The project team reviewed the operating experience provided in the OCGS LRA, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant’s boraflex rack management program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.2.13.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the boraflex rack management program in OCGS LRA, Appendix A, Section A.1.15, which states that the Boraflex Rack Management Program is an existing program that provides for aging management of the Boraflex neutron poison material. The program consists of monitoring the condition of Boraflex by routinely sampling fuel pool silica levels, periodically trending the condition of Boraflex using RACKLIFE, and periodically performing in-situ measurement of boron-10 areal density using the BADGER device. The BADGER device test is conducted every 3 years.

The project team also reviewed the License Renewal Commitment List to confirm that this program will be implemented prior to the period of extended operation as item 15 of the commitments.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.15, found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.2.13.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report, are consistent with the GALL Report. In addition, the project team has reviewed the exception and the associated justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. The project team also reviewed the UFSAR Supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.14 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (OCGS AMP B.1.16)

In the OCGS LRA, Appendix B, Section B.1.16, the applicant stated that OCGS AMP B.1.16, "Inspection of Overhead Heavy Load and Light Load (Related To Refueling) Handling Systems," is an existing plant program that is consistent with GALL AMP XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related To Refueling) Handling Systems," with an exception and enhancements.

3.0.3.2.14.1 Program Description

In the OCGS LRA, the applicant stated that this program provides for periodic visual inspections of overhead heavy load and light load (related to refueling) handling systems. The program is implemented through station procedures and is relied upon to manage loss of material of crane and hoist structural components, including the bridge, the trolley, bolting, lifting devices, and the rail system within the scope of 10 CFR 54.4. Bolting is monitored for loss of material, and loss of preload by inspecting for missing, detached or loosened bolts. The program relies on procurement controls and installation practices, defined in plant procedures, to ensure that only approved lubricants and proper torque are applied consistent with the NUREG-1801 Bolting Integrity Program. Inspection frequency is annual for cranes and hoists that are accessible during plant operation, and every 2 years for cranes and hoists that are only accessible during refueling outages.

3.0.3.2.14.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.16 is consistent with GALL AMP XI.M23, with an exception and enhancements.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.16, including basis document, PBD-AMP-B.1.16, ?Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems," Revision 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M23. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.16 and associated bases documents to determine their consistency with GALL AMP XI.M23.

The project team reviewed those portions of the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program for which the applicant claims consistency with GALL AMP XI.M23 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program conforms to the recommended

GALL AMP XI.M23, ?Inspection of Overhead Heavy Load and Light Load (Related To Refueling) Handling Systems," with the exception and enhancements described below.

3.0.3.2.14.3 Exceptions to the GALL Report

In the OCGS LRA, the applicant stated the following exception to the GALL Report program elements:

Element:	5. Monitoring and Trending
Exception:	NUREG-1801 indicates that the number and magnitude of lifts made by the crane are reviewed. The Oyster Creek program does not require tracking of the number and magnitude of lifts. Administrative controls are implemented to ensure that only allowable loads are handled. As discussed in the Crane Load Cycle Limit time-limited aging analysis (TLAA), the projected number of load cycles for 60 years for the reactor building crane is 2800 cycles. The projected number of load cycles for 60 years for the turbine building and heater bay cranes are 2000 and 600 cycles respectively. The reactor building crane, the turbine building and the heater bay cranes were designed for 20,000 to 100,000 load cycles. Thus tracking the number of lifts, or load cycles, is not required because the projected number of crane load cycles for 60 years is significantly lower than the design value.

The GALL Report identifies the following recommendations for the ?monitoring and trending' program element associated with the exception taken:

5. *Monitoring and Trending:* Monitoring and trending are not required as part of the crane inspection program.

In reviewing this exception, the project team noted that, while early versions of the GALL Report included a recommendation to monitor the number and magnitude of lifts made by the cranes, the approved September 2005 Revision 1 version of the GALL Report no longer includes this recommendation. Therefore, the applicant's program element is consistent with the GALL Report with respect to monitoring the number of lifts, and no exception is required. In Attachment 1, item B.1.16 of its reconciliation document, the applicant stated that this exception was deleted.

On the basis that the approved September 2005, Revision 1, version of GALL does not recommend monitoring the number of lifts made by each crane, the project team determined that the applicant's program element is consistent with the GALL Report and this exception is not required.

3.0.3.2.14.4 Enhancements

In the OCGS LRA, the applicant identified the following enhancements in order to meet the GALL Report program elements:

Enhancement 1

Element: 1. Scope of Program

Enhancement: Increase the scope of the program to include additional hoists identified as potential Seismic II/I concern, in accordance with 10 CFR 54.4(a)(2).

The GALL Report identifies the following recommendations for the ?scope of program" program element associated with the stated enhancement:

> 1. *Scope of Program*: The program manages the effects of general corrosion on the crane and trolley structural components for those cranes that are within the scope of 10 CFR 54.4, and the effects of wear on the rails in the rail system.

The project team noted that Section 2.3.3.11 of the OCGS LRA stated that other cranes and hoists that are not in scope of NUREG-0612 but travel in the vicinity of safety-related systems, structures, and components (SSCs) are also in scope of license renewal; if it is determined that their failure will impact a safety-related function. As a result, the reactor building (RB) crane, the turbine building crane, turbine building heater bay crane, recirculation pumps monorail, spent fuel pool jib cranes, containment vacuum breakers jib cranes/hoists, equipment handling monorail (RB El. 95'), and the torus bay monorail are in the scope of license renewal. This enhancement makes the AMP consistent with the recommendations of the GALL Report.

On this basis, the project team found the enhancement acceptable since when the enhancement is implemented, OCGS AMP B.1.16, "Inspection of Overhead Heavy Load and Light Load Handling Systems," will be consistent with GALL AMP XI.M23 and will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 2

Elements: 3. Parameters Monitored or Inspected
4. Detection of Aging Effects

Enhancement: The program will provide for specific inspections for rail wear.

The GALL Report identifies the following recommendations for the ?parameters monitored or inspected" and ?detection of aging effects" program elements associated with the stated enhancement:

> 3. *Parameters Monitored or Inspected*: The program evaluates the effectiveness of the maintenance monitoring program and the effects of past and future usage on the structural reliability of cranes.
>
> 4. *Detection of Aging Effect:* Crane rails and structural components are visually inspected on a routine basis for degradation.

The project team reviewed the GALL Report recommendations for these program elements and determined that the addition of specific inspections for rail wear will make the applicant's AMP consistent with the recommendations in the GALL Report; therefore, this enhancement is acceptable.

On this basis, the project team found the enhancement acceptable since when the enhancement is implemented, OCGS AMP B.1.16, "Inspection of Overhead Heavy Load and Light Load Handling Systems," will be consistent with GALL AMP XI.M23 and will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 3

Elements:	3. Parameters Monitored or Inspected 4. Detection of Aging Effects 6. Acceptance Criteria
Enhancement:	The program will provide for specific inspections for corrosion of crane and hoist structural components, including the bridge, the trolley, bolting, lifting devices, and the rail system.

The GALL Report identifies the following recommendations for the ?parameters monitored or inspected," ?detection of aging effects," and ?acceptance criteria" program elements associated with the stated enhancement:

3. *Parameters Monitored or Inspected:* The program evaluates the effectiveness of the maintenance monitoring program and the effects of past and future usage on the structural reliability of cranes.

4. *Detection of Aging Effect:* Crane rails and structural components are visually inspected on a routine basis for degradation.

6. *Acceptance Criteria:* Any significant visual indication of loss of material due to corrosion or wear is evaluated according to applicable industry standards and good industry practice. The crane may also have been designed to a specific Service Class as defined in the Crane Manufacturers Association of America, Inc. (CMAA) Specification #70 (or later revisions), or CMAA Specification #74 (or later revisions). The specification that was applicable at the time the crane was manufactured is used.

The project team reviewed the GALL Report recommendations for these program elements and determined that the addition of specific inspections for corrosion of crane and hoist structural components, including the bridge, the trolley, bolting, lifting devices, and the rail system will make the applicant's AMP consistent with the recommendations in the GALL Report. On this basis, the project team determined that this enhancement is acceptable.

On this basis, the project team found the enhancement acceptable since when the enhancement is implemented, OCGS AMP B.1.16, "Inspection of Overhead Heavy Load and Light Load Handling Systems," will be consistent with GALL AMP XI.M23 and will provide additional assurance that the effects of aging will be adequately managed.

Considering the relatively short time period remaining before OCGS enters the license renewal period, the project team inquired about the status of implementing procedures required for new AMPs, and for significant enhancements to existing AMPs. The applicant was asked to provide (a) the status of the implementing procedures for each enhancement to the existing program; (b) the schedule for initiating each of the enhancements to the existing program; (c) a sample of an implementing procedure for one enhancement to the existing program; and (d) the results of any enhanced inspections completed.

In its response, the applicant stated that all program enhancements will be completed and issued for implementation by December 1, 2006. Enhancements to the program that are related to cranes and hoists that are accessible only during a refueling outage will be expedited and issued by April 2006. Implementation of the enhancements will be completed by December 31, 2007. The enhancements will be initiated following completion of enhanced procedures. Therefore, no enhanced inspection results were available for review by the project team.

The project team reviewed the applicant's response and determined that it is acceptable since all activities will be completed prior to entering the period of extended operation.

3.0.3.2.14.5 Operating Experience

In the OCGS LRA, the applicant stated that the plant operating and maintenance experience review identified no incidents of failure of passive cranes and hoists structural components due to age related degradation. Minor non-age related degradation has been identified in non-load bearing components during the inspections. The degradation was repaired and documented in accordance with the corrective active process.

The applicant was asked to provide documentation to support the claim that no incidents of failure of passive crane and hoist structural components have occurred. In response, the applicant stated that the Corrective Action Program (CAP) at Oyster Creek requires documentation of conditions adverse to quality. For AMP B.1.16, a search of the CAP database was performed to identify if loss of material in passive components of cranes or hoists resulted in dropping a load or impacting safety-related structures, systems, or components. No such cases were identified. Based upon this finding, it was concluded that there were no failures of passive components on cranes or hoists due to age-related degradation. As examples of the types of incidents found in the database, CAPs O2000-1446, O2004-601, and O2004-2877 were provided for review. The project team reviewed these documents, which included the following incidents:

- The reactor building crane main hoist failed to move due to the airbrake limit switch being out of adjustment

- The lower limit switch for the main and auxiliary hoists were found not to be functional during an inspection and a warning light did not illuminate

- The heater bay crane failed due to a shorted drive motor

The project team determined that none of the incidents were due to age-related degradation of passive long-lived components, such as structural members or rails.

The project team reviewed the operating experience provided in the OCGS LRA, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant's inspection of overhead heavy load and light load (related to refueling) handling systems program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.2.14.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for this AMP in OCGS LRA, Appendix A, Section A.1.16, which stated that the inspection of overhead heavy load and light load (related to refueling) handling systems aging management program is an existing program that confirms the effectiveness of the maintenance monitoring program and the effects of past and future usage on the structural reliability of cranes and hoists. Administrative controls ensure that only allowable loads are handled. As discussed in the crane load cycle limit time-limited aging analysis (TLAA), the projected number of load cycles for 60 years is significantly lower than the design value and thus fatigue is not a concern for cranes during the period of extended operation. Crane and hoist structural components, including the bridge, the trolley, bolting, lifting devices, and the rail system are visually inspected periodically for loss of material. Bolting is also monitored for loss of preload by inspecting for missing, detached, or loosened bolts. The program relies on procurement controls and installation practices, defined in plant procedures, to ensure that only approved lubricants and proper torque are applied to bolting.

Prior to the period of extended operation, the scope of the program will be enhanced to include additional hoists that have been identified as being in scope for license renewal per 10 CFR 54.4(a)(2). The program will also be enhanced to include inspections for rail wear, and loss of material due to corrosion of crane and hoist structural components.

The project team noted that the statements regarding visual inspections for loss of material are unclear since it is stated that crane and hoist structural components, including the bridge, the trolley, bolting, lifting devices, and the rail system are visually inspected periodically for loss of material; however, the program will be enhanced to include inspections for rail wear and loss of material due to corrosion of crane and hoist structural components. The applicant was asked to clarify specifically what aging management activities are included in the existing program, and what the enhancement will add to the existing program.

In its response, the applicant stated that the existing program has been effective in managing general corrosion of structural components, and wear on the rails for cranes and trolleys. However, the implementing procedures do not explicitly identify steps to inspect for these aging mechanisms. Therefore, as stated in the OCGS LRA, Appendix B.1.16, the program will be enhanced to provide for specific inspections for rail wear, and for corrosion of crane and hoist structural components. The project team determined that inspections for general corrosion and rail wear are currently being performed as good practices; however, they are not explicitly included in the OCGS implementing procedures. This enhancement will provide a means of formally incorporating these inspections into the OCGS implementing procedures. On this basis, the project team determined that the statements in the applicant's UFSAR supplement are acceptable.

The project team also reviewed the applicant's license renewal commitment list in Appendix A of the OCGS LRA, and confirmed that the enhancements to this program are identified and will be implemented prior to the period of extended operation as item 16 of the commitments.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.16, found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table, and as required by 10 CFR 54.21(d).

3.0.3.2.14.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report are consistent with the GALL Report. In addition, the project team reviewed the exception and its associated justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. Also, the project team reviewed the enhancements and determined that the implementation of the enhancements prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The project team also reviewed the UFSAR Supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.15 BWR Reactor Water Cleanup System (OCGS AMP B.1.18)

In the OCGS LRA, Appendix B, Section B.1.18, the applicant stated that OCGS AMP B.1.18, "BWR Reactor Water Cleanup System," is an existing plant program that is consistent with GALL AMP XI.M25, "BWR Reactor Water Cleanup System," with an exception.

3.0.3.2.15.1 Program Description

In the OCGS LRA, the applicant stated that this program describes the requirements for augmented inservice inspection (ISI) for SCC or IGSCC on stainless steel reactor water cleanup system piping welds outboard of the second containment isolation valves. The program includes inspection guidelines delineated in NUREG-0313, Rev. 2, and NRC GL 88-01. The program also provides for water chemistry control in accordance with BWRVIP-130: ?BWR Vessel and Internals Project BWR Water Chemistry Guidelines" to minimize the potential of crack initiation and growth due to SCC or IGSCC.

The applicant also stated in the OCGS LRA that, in accordance with GL 88-01, Supplement 1, upgrades and enhancements have been implemented to the RWCU isolation valves in accordance with GL 89-10 to ensure that the valves will produce sufficient thrust to perform their design basis function, which is the isolation of containment in the event of a pipe break downstream of the valves. Based on these upgrades/ enhancements, an effective hydrogen water chemistry program, and the complete lack of cracking found during any of the RWCU piping weld inspections under GL 88-01, all inspection requirements for the portion of the RWCU system outboard of the second containment isolation valves have been eliminated.

The applicant further stated in the OCGS LRA that the reactor coolant system (RCS) chemistry activities that support the aging management program for the RWCU system consist of preventive measures that are used to manage cracking in license renewal components exposed to reactor water and steam. RCS chemistry activities provide for monitoring and controlling RCS water chemistry using Oyster Creek procedures and processes based on the 2004 revision to EPRI TR-103515, which is BWRVIP-130, ?BWR Vessel and Internals Project BWR Water Chemistry Guidelines." The BWR water chemistry guidelines include information to develop proactive plant-specific water chemistry programs to minimize IGSCC.

3.0.3.2.15.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.18 is consistent with GALL AMP XI.M25, with an exception.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.18, including basis document, PBD-AMP-B.1.18, ?BWR Reactor Water Cleanup System," Revision 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M25. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.18 and associated bases documents to determine their consistency with GALL AMP XI.M25.

In reviewing this program, the project team noted that Section 2.3.3.32 of the OCGS LRA identifies the entire RWCU as being in the scope of license renewal; however, the applicant limited the scope of this program to include only that portion of the RWCU system outboard of the second containment isolation valve. The project team asked the applicant 1) confirmation that the scope of this AMP included only non-safety-related piping outboard of the second containment isolation valves, and 2) clarification as to what program would be used to manage aging for the safety-related portion of the RWCU system inboard of the second containment isolation valves.

In its response, the applicant stated that the OCGS BWR reactor water cleanup system aging management program addresses SCC and IGSCC in 4-inch or larger austenitic stainless steel, non-safety-related, non-RCPB (reactor coolant pressure boundary) reactor water cleanup system piping outboard of the second primary containment isolation valves, above 200ºF. For austenitic stainless steel non-safety-related, non-RCPB reactor water cleanup system piping less than 4-inch, the Water Chemistry Program (AMP B.1.2) and the One-Time Inspection Program (AMP B.1.24) apply.

The applicant further stated that SCC and IGSCC in 4-inch or larger austenitic stainless steel, safety-related, RCPB portions of the reactor water cleanup system inboard of the second primary containment isolation valves, above 200ºF, are addressed by the OCGS BWR stress corrosion cracking program (AMP B.1.7), the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (AMP B.1.1), and the Water Chemistry Program (AMP B.1.2). For austenitic stainless steel safety-related, RCPB reactor water cleanup system piping less than 4 inches, the ASME Section XI Inservice Inspection, subsections IWB, IWC, and IWD program (AMP B.1.1), the One-Time Inspection Program (AMP B.1.24), and the Water Chemistry Program (AMP B.1.2) apply.

The project team reviewed the applicant’s response and determined that it is acceptable since it appropriately limits the scope of this AMP to non-safety-related piping outboard of the second containment isolation valves, in accordance with the guidance provided in NRC GLs 88-01 and 89-10. Piping inboard of the second containment isolation valves will remain subject to inspection under the ASME Section XI Inservice Inspection, subsections IWB, IWC, and IWD program (AMP B.1.1), or the One-Time Inspection Program (B.1.24).

The project team also noted that the description of AMP B.1.18 in the OCGS LRA stated that 1) GL 88-01, Supplement 1, upgrades and enhancements have been implemented to the RWCU isolation valves in accordance with GL 89-10, 2) an effective hydrogen water chemistry program is being implemented, and 3) a complete lack of cracking was found during the RWCU piping weld inspections under GL 88-01. Therefore, all inspection requirements for the portion of the RWCU system outboard of the second containment isolation valves have been eliminated. The project team asked the applicant to provide documentation to support the elimination of inspection requirements for the portion of the RWCU system outboard of the second containment isolation valves.

In its response, the applicant stated the GPU letter to NRC 1940-00-20096, dated April 13, 2000, ?Oyster Creek Request to Eliminate Inspections," and OCGS document OC-2, ?IGSCC Inspection Program (GL 88-01 and BWRVIP-75)," document the basis for this finding. No formal response was received from the NRC for letter 1940-00-20096; however, since all required actions identified in previous correspondence with the NRC that would allow for the elimination of the RWCU augmented inspections were completed, no response was expected. Therefore, Oyster Creek considered this request approved.

The project team reviewed GPU letter to NRC 1940-00-20096, dated April 13, 2000, ?Oyster Creek Request to Eliminate Inspections," and OCGS document OC-2, ?IGSCC Inspection Program (GL 88-01 and BWRVIP-75)." OCGS document OC-2 includes a list of RWCU system welds and summarizes the results of the IGSCC inspections conducted to date. The project team's review of the results reported in this document confirm that the RWCU system welds have been inspected and no indications of IGSCC were found, which supports the applicant's claim. As noted in the GALL Report for AMP XI.M25, the elimination of RWCU weld inspections outboard of the second containment isolation valves is acceptable if the guidance in GL 89-10 is completed to verify the isolation function of these valves, and no indications of IGSCC have been found in previous inspections. Since the applicant has successfully completed all required actions, the inspections were appropriately eliminated. On this basis, the project team determined that the applicant's response was acceptable.

The project team reviewed those portions of the BWR Reactor Water Cleanup System program for which the applicant claims consistency with GALL AMP XI.M25 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's BWR reactor water cleanup system program conforms with the recommended GALL AMP XI.M25, "BWR Reactor Water Cleanup System," with the exception described below.

3.0.3.2.15.3 Exceptions to the GALL Report

In the OCGS LRA, the applicant stated the following exception to the GALL Report AMP elements:

Elements:	Program Description 2. Preventive Actions
Exception:	NUREG-1801 indicates that water chemistry control is in accordance with BWRVIP-29, ?EPRI Report TR-103515-R1, BWR Water Chemistry Guidelines" dated 1996. The Oyster Creek Water Chemistry Program is based on BWRVIP-130, ?BWR Vessel and Internals Project BWR Water Chemistry Guidelines" dated 2004.

The GALL Report identifies the following recommendations for the ?program description" and ?preventive actions" program elements associated with the exception taken:

Program Description: The program includes inservice inspection (ISI) and monitoring and control of reactor coolant water chemistry to manage the effects of SCC or IGSCC on the intended function of austenitic stainless steel (SS) piping in the reactor water cleanup (RWCU) system. Based on the Nuclear Regulatory Commission (NRC) criteria related to inspection guidelines for RWCU piping welds outboard of the second isolation valve, the program includes the measures delineated in NUREG-0313, Rev. 2, and NRC

GL 88-01. Coolant water chemistry is monitored and maintained in accordance with the Electric Power Research Institute (EPRI) guidelines in boiling water reactor vessel and internals project (BWRVIP) -29 (TR-103515) to minimize the potential of cracking due to SCC or IGSCC.

2. *Preventive Actions:* The comprehensive program outlined in NUREG-0313 and NRC GL 88-01 addresses improvements in all three elements that, in combination, cause SCC or IGSCC. These elements are a susceptible (sensitized) material, a significant tensile stress, and an aggressive environment. The program delineated in NUREG-0313 and NRC GL 88-01 includes recommendations regarding selection of materials that are resistant to sensitization, use of special processes that reduce residual tensile stresses, and monitoring and maintenance of coolant chemistry. The resistant materials are used for new and replacement components and include low-carbon grades of austenitic SS and weld metal, with a maximum carbon of 0.035 wt.% and a minimum ferrite of 7.5% in weld metal and cast austenitic stainless steel (CASS). Inconel 82 is the only commonly used nickel-base weld metal considered resistant to SCC; other nickel-alloys, such as Alloy600, are evaluated on an individual basis. Special processes are used for existing as well as new and replacement components. These processes include solution heat treatment, heat sink welding, induction heating, and mechanical stress improvement. The program delineated in NUREG-0313 and NRC GL 88-01 varies depending on the plant-specific reactor water chemistry to mitigate SCC or IGSCC.

The project team reviewed the applicant’s exception as part of the OCGS Water Chemistry Program (AMP B.1.2) and determined that it is acceptable. The evaluation of this exception is discussed in Section 3.0.3.2.2 of this audit report.

3.0.3.2.15.4 Enhancements

None.

3.0.3.2.15.5 Operating Experience

In the OCGS LRA, the applicant stated that no indications of IGSCC have been found in the RWCU system, which is not stress improved. The following mitigative actions have also been implemented to reduce the susceptibility of the RWCU System to IGSCC:

- Improved water chemistry guidelines (BWR Water Chemistry Guidelines 2004 Revision (BWRVIP-130))
- Hydrogen Water Chemistry (HWC)
- Noble Metals Chemical Addition (NMCA)

The project team asked clarification on when the hydrogen water chemistry and noble metals chemical addition mitigative actions were initiated at Oyster Creek. In its response, the applicant stated the hydrogen water chemistry was implemented during cycle 12 (1990), and noble metals chemical addition was implemented in outage 1R19 (2002).

The project team reviewed the operating experience provided in the OCGS LRA and program basis documents, interviewed the applicant's technical staff, and confirmed that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience, and discussions with the applicant's technical staff, the project team determined that the applicant's BWR reactor water cleanup system program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.2.15.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for this AMP in the OCGS LRA, Appendix A, Section A.1.18, which stated that the BWR reactor water cleanup system aging management program is an existing program that describes the requirements for augmented inservice inspection (ISI) for SCC or IGSCC on stainless steel reactor water cleanup system piping welds outboard of the second containment isolation valves. The program includes inspection guidelines delineated in NUREG-0313, Rev. 2 and NRC GL 88-01. The program also provides for water chemistry control in accordance with BWRVIP-130: ?BWR Vessel and Internals Project BWR Water Chemistry Guidelines" to minimize the potential of crack initiation and growth due to SCC or IGSCC.

In accordance with GL 88-01, Supplement 1, upgrades and enhancements have been implemented to the RWCU isolation valves in accordance with GL 89-10 to ensure that the valves will produce sufficient thrust to perform their design basis function, which is the isolation of containment in the event of a pipe break downstream of the valves. Based on these upgrades/enhancements, an effective hydrogen water chemistry program, and the complete lack of cracking found during any of the RWCU piping weld inspections under GL 88-01, all inspection requirements for the portion of the RWCU system outboard of the second containment isolation valves have been eliminated.

Reactor coolant system (RCS) chemistry activities that support the aging management program for the RWCU system consist of preventive measures that are used to manage cracking in license renewal components exposed to reactor water and steam. RCS chemistry activities provide for monitoring and controlling RCS water chemistry using Oyster Creek procedures and processes based on BWRVIP-130: ?BWR Vessel and Internals Project BWR Water Chemistry Guidelines." The BWR water chemistry guidelines include information to develop proactive plant-specific water chemistry programs to minimize IGSCC.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.18, found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.2.15.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report, are consistent with the GALL Report. In addition, the project team reviewed the exception and the associated justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. The project team also reviewed the UFSAR Supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.16 Fire Protection (OCGS AMP B.1.19)

In OCGS LRA, Appendix B, Section B.1.19, the applicant stated that OCGS AMP B.1.19, "Fire Protection," is an existing plant program that is consistent with GALL AMP XI.M26, "Fire Protection," with an exception and enhancements.

3.0.3.2.16.1 Program Description

In the OCGS LRA, the applicant stated that this program provides for aging management of various fire protection-related components within the scope of license renewal. The program provides for visual inspections of fire barrier penetration seals for signs of degradation, such as change in material properties, cracking, and loss of material, through periodic inspection, surveillance, and maintenance activities. The inspections are implemented through recurring task work orders and station procedures.

The applicant also stated that the program provides for visual inspection of fire barrier walls, ceilings, and floors in structures within the scope of license renewal for the aging effects of cracking and loss of material. The inspections are implemented through recurring task work orders and station procedures.

The program also provides for periodic visual inspections of fire doors for holes in skin, wear, or missing parts. Fire door clearances are checked during periodic inspections and when fire doors and components are repaired or replaced. Additionally, periodic functional tests of fire doors are implemented through recurring task work orders and station procedures.

The applicant further stated that the program will provide for managing loss of material aging effects for the fuel oil systems for the Oyster Creek diesel-driven fire pumps by the performance of periodic fuel oil system surveillance tests that are implemented through recurring task work orders and station procedures.

The program will provide for aging management of external surfaces of the Oyster Creek carbon dioxide and Halon fire suppression system components for corrosion and mechanical damage through periodic operability tests based on NFPA codes and visual inspections. Testing and inspections are implemented through recurring task work orders and station procedures.

3.0.3.2.16.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.19 is consistent with GALL AMP XI.M26, with an exception and enhancements.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.19, including the program basis document, PBD-AMP-B.1.19, ?Fire Protection," Rev. 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.26. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.19 and associated bases documents to determine their consistency with GALL AMP XI.M26.

The project team reviewed those portions of the fire protection program for which the applicant claims consistency with GALL AMP XI.M26 and found that they are consistent with the GALL

Report AMP. The project team found that the applicant's fire protection program conforms to the recommended GALL AMP XI.M26, "Fire Protection," with the exception and enhancements described below.

3.0.3.2.16.3 <u>Exceptions to the GALL Report</u>

In the OCGS LRA, the applicant stated the following exception to the GALL Report program elements:

Elements:	3. Parameters Monitored or Inspected 4. Detection of Aging Effects
Exception:	NUREG-1801 recommends visual inspection and functional testing of the halon and CO_2 fire suppression systems at least once every six months. The Oyster Creek halon and low-pressure carbon dioxide fire suppression systems undergo operational testing and inspections every 18 months. Additionally, the halon fire suppression system undergoes an inspection of the system charge (storage tank weight/level and pressure) every 6 months, and the low-pressure carbon dioxide fire suppression system undergoes a weekly tank check and monthly valve position alignment verification. These test frequencies are considered sufficient to ensure system availability and operability based on the station's operating history that shows no aging related events that have adversely affected the systems' operation. The test procedures will be enhanced to include visual inspections of the component external surfaces. Test and inspection frequency adequacy will be evaluated as part of the corrective action process based on actual test and inspection results.

The GALL Report identified the following recommendations for the ?parameters monitored or inspected" and ?detection of aging effects" program elements associated with the exception taken:

3. *Parameters Monitored or Inspected*: The periodic visual inspection and functional test of the halon and CO2 systems is performed at least once every six months to examine the signs of degradation.

4. *Detection of Aging Effects*: Visual inspection of the alon/CO_2 fire suppression system detects any sign of added degradation, such as corrosion, mechanical damage, or damage to dampers. The periodic function test and inspection performed at least once every six months detects degradation of the halon/CO_2 fire suppression system before the loss of the component intended function.

In reviewing this exception, the project team noted that the Oyster Creek fire protection aging management program directs halon fire suppression system surveillance that verifies halon storage tank weight, level, and pressure once every six months. Actuation of the system (automatic and manual, including dampers) and flow is verified every 18 months. The program also directs performance of functional operability testing and flow verification, including operation of associated ventilation dampers, and manual and automatic actuation. The low-pressure carbon dioxide fire suppression system undergoes a weekly tank check and monthly valve position alignment verification. Visual aging degradation inspections are performed during the operability tests. Existing operability testing requirements are implemented through station procedures. The project team noted that the current licensing basis for periodic visual inspection and functional test frequency of the halon and CO2 systems is every 18 months.

As described in Section 3.0.3.2.16.4 below, OCGS test procedures will be enhanced to include visual inspections of the component external surfaces for signs of corrosion and mechanical damage. In LRA Section B.1.19 and in response to an audit question, the applicant stated that plant-specific operating experience has shown no loss of material on the external surfaces of components in the halon and carbon dioxide systems that have adversely affected system operation. The applicant's review of station operating experience did not identify any occurrence of aging related degradation which adversely affected the operation of the halon or CO_2 systems.

While the frequency of functional testing exceeds the frequency recommended in NUREG-1801, AMP XI.M26, the project team determined that it is sufficient to ensure system availability and operability based on the enhancement to include visual inspections of the component external surfaces for signs of corrosion and mechanical damage. In addition, the station operating history, indicates no occurrence of aging-related events having adversely affected system operation. Based on its review of the applicant's program and plant-specific operating experience, the project team concurred that the 18-month frequency is adequate for aging management considerations. On this basis, the project team found this exception acceptable.

3.0.3.2.16.4 Enhancements

In the OCGS LRA, the applicant identified the following enhancements in order to meeting the GALL Report program elements:

Enhancement 1

Elements:	3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring and Trending 6. Acceptance Criteria
Enhancement:	The fire protection aging management program will be enhanced to include inspection for corrosion and mechanical damage on external surfaces of piping and components for the Oyster Creek halon and carbon dioxide fire suppression systems.

The GALL Report identified the following recommendations for the ?parameters monitored or inspected," ?detection of aging effects," ?monitoring and trending," and ?acceptance criteria" program elements associated with the enhancement:

> 3. *Parameters Monitored or Inspected*: The periodic visual inspection and function test is performed at least once every six months to examine the signs of degradation of the halon/CO2 fire suppression system. Material conditions that may affect the performance of the system, such as corrosion, mechanical damage, or damage to dampers, are observed during these tests.

4. *Detection of Aging Effects*: Visual inspection of the halon/CO2 fire suppression system detects any sign of added degradation, such as corrosion, mechanical damage, or damage to dampers. The periodic function test and inspection performed at least once every six months detects degradation of the halon/CO2 fire suppression system before the loss of the component intended function.

5. *Monitoring and Trending*: The performance of the halon/CO2 fire suppression system is monitored during the periodic test to detect any degradation in the system. These periodic tests provide data necessary for trending.

6. *Acceptance Criteria*: ...any signs of corrosion and mechanical damage of the halon/CO2 fire suppression system are not acceptable.

In reviewing this enhancement, the project team noted that the applicant's fire protection aging management program currently includes periodic halon and low-pressure carbon dioxide fire suppression system inspections, including inspections for operation of the dampers. This enhancement will add visual inspections of the piping and components for external surface corrosion degradation and mechanical damage, as recommended in the GALL Report. The addition of these visual inspections will provide additional assurance that aging degradation of the fire protection system piping and components will be adequately managed; therefore this enhancement is acceptable.

On this basis, the project team found this enhancement acceptable since when the enhancement is implemented, OCGS AMP B.1.19, "Fire Protection," will be consistent with GALL AMP XI.M26 and will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 2

Elements:	3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring and Trending 6. Acceptance Criteria
Enhancement:	The fire protection aging management program will be enhanced to provide specific guidance for examining the fire pump diesel fuel supply systems for corrosion during pump tests.

The GALL Report identified the following recommendations for the ?parameters monitored or inspected," ?detection of aging effects," ?monitoring and trending," and ?acceptance criteria" program elements associated with the enhancement:

3. *Parameters Monitored or Inspected*: The diesel-driven fire pump is under observation during performance tests such as flow and discharge tests, sequential starting capability tests, and controller function tests for detection of any degradation of the fuel supply line.

4. *Detection of Aging Effects*: Periodic tests performed at least once every refueling outage, such as flow and discharge tests, sequential starting capability tests, and controller function tests performed on diesel-driven fire pump ensure fuel supply line

performance. The performance tests detect degradation of the fuel supply lines before the loss of the component intended function.

5. *Monitoring and Trending*: The performance of the fire pump is monitored during the periodic test to detect any degradation in the fuel supply lines. Periodic testing provides data (e.g., pressure) for trending necessary.

6. *Acceptance Criteria*: No corrosion is acceptable in the fuel supply line for the diesel-driven fire pump.

In reviewing this enhancement, the project team noted that the applicant's fire protection aging management program currently includes operational tests of the diesel-driven fire pumps to record flow and discharge, starting capability, and controller function, to be performed every 18 months. These performance tests detect degradation of the fuel supply lines before the loss of the component intended function. This enhancement will add a visual inspection for detecting any degradation of external surfaces of the fuel supply line during engine operation, as recommended in the GALL Report. Since the inclusion of visual inspections will provide additional assurance that aging degradation of the fuel supply lines is adequately managed, this enhancement is acceptable.

On this basis, the project team found this enhancement acceptable since when the enhancement is implemented, OCGS AMP B.1.19, "Fire Protection," will be consistent with GALL AMP XI.M26 and will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 3

Elements:	3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring and Trending 6. Acceptance Criteria
Enhancement:	The fire protection aging management program will be enhanced to provide additional inspection guidance for degradation of fire barrier walls, ceilings, and floors such as spalling and loss of material caused by freeze-thaw, chemical attack, and reaction with aggregates. Enhancements will be implemented prior to the period of extended operation.

The GALL Report identified the following recommendations for the ?parameters monitored or inspected," ?detection of aging effects," ?monitoring and trending," and ?acceptance criteria" program elements associated with the enhancement:

3. *Parameters Monitored or Inspected*: Visual inspection of the fire barrier walls, ceilings, and floors examines any sign of degradation such as cracking, spalling, and loss of material caused by freeze-thaw, chemical attack, and reaction with aggregates.

4. *Detection of Aging Effects*: Visual inspection by fire protection qualified inspectors of the fire barrier walls, ceilings, and floors, performed in walkdowns at least once every refueling outage ensures timely detection of concrete cracking, spalling, and loss of material.

5. *Monitoring and Trending*: Concrete cracking, spalling, and loss of material are detectable by visual inspection and based on operating experience, visual inspection performed at least once every refueling outage detects any sign of degradation of the fire barrier walls, ceilings, and floors before there is a loss of the intended function.

6. *Acceptance Criteria*: Inspection results are acceptable if there are...no visual indications of concrete cracking, spalling and loss of material of fire barrier walls, ceilings, and floors;

In reviewing this enhancement, the project team noted that, as part of the applicant's fire protection aging management program, the aging effects on the intended function of fire barrier walls, ceilings, and floors that perform a fire barrier function are managed using specific inspection parameters in accordance with industry codes, standards, and guidelines that ensure aging degradation is detected and corrected prior to loss of intended functions. This enhancement will add enhanced inspections of fire barrier walls, ceilings, and floors look for signs of degradation including but not limited to cracking, spalling, and loss of material caused by freeze-thaw, aggressive chemical attack, reaction with aggregates, and corrosion of embedded steel, as recommended in the GALL Report. Since these enhanced inspections will provide additional assurance that aging degradation of fire barrier walls, ceilings, and floors will be adequately managed, this enhancement is acceptable.

On this basis, the project team found this enhancement acceptable since when the enhancement is implemented, OCGS AMP B.1.19, "Fire Protection," will be consistent with GALL AMP XI.M26 and will provide additional assurance that the effects of aging will be adequately managed.

In reviewing the program basis document, PBD-AMP-B.1.19, the audit team noted that there is a discrepancy between OCGS LRA, Section B.1.19, ?Fire Protection," and the program basis document PBD-AMP-B.1.19, Rev. 0. The program basis document stated an enhancement related to periodic visual inspections of fire door surface integrity and clearance checks; however, this enhancement is not included in the OCGS LRA, nor is it addressed in the OCGS reconciliation document. The project team discussed this discrepancy with the applicant, and the applicant committed to add this enhancement to the OCGS LRA.

In its letter dated April 17, 2006 (ML061150320), the applicant committed to revise AMP B.1.19 in the OCGS LRA to add the following enhancement to the OCGS fire protection program, related to periodic visual inspections of fire door surface integrity and clearance checks, as described in the program basis document, PBD-AMP-B.1.19, to the OCGS LRA. **This is Audit Commitment 3.0.3.2.16-1.**

<u>Enhancement 4</u>

Elements: 3. Parameters Monitored or Inspected
4. Detection of Aging Effects
5. Monitoring and Trending
6. Acceptance Criteria

Enhancement: The fire protection aging management program will be enhanced to require that surface integrity and clearances of fire doors in the scope of license renewal be routinely inspected every two years. The program currently requires these doors be intact and verified functional, with fire doors identified as secondary containment receiving routine clearance checks. Other fire doors in the scope of license renewal currently receive clearance checks if they have been damaged or undergone maintenance such that the clearances may have been physically altered. The enhancement of requiring routine surface integrity and clearance checks for all fire doors in the scope of license renewal will provide assurance that degradation of fire doors prior to loss of intended function will be detected.

The GALL Report identified the following recommendations for the ?parameters monitored or inspected,” ?detection of aging effects,” ?monitoring and trending,” and ?acceptance criteria” program elements associated with the enhancement:

> 3. *Parameters Monitored or Inspected*: Fire-rated doors are visually inspected on a plant specific interval to verify the integrity of door surfaces and for clearances. The plant specific inspection intervals are to be determined by engineering evaluation to detect degradation of the fire doors prior to the loss of intended function.
>
> 4. *Detection of Aging Effects*: Visual inspection by fire protection qualified inspectors detects any sign of degradation of the fire door such as wear and missing parts. Periodic visual inspection and function tests detect degradation of the fire doors before there is a loss of intended function.
>
> 5. *Monitoring and Trending*: Based on operating experience, degraded integrity or clearances in the fire door are detectable by visual inspection performed on a plant-specific frequency. The visual inspections detect degradation of the fire doors prior to loss of the intended function.
>
> 6. *Acceptance Criteria*: Inspection results are acceptable if there are...no visual indications of missing parts, holes, and wear and no deficiencies in the functional tests of fire doors.

In reviewing this enhancement, the project team noted that the applicant’s fire protection aging management program will direct that fire doors in the scope of license renewal are to be visually inspected by designated qualified personnel for signs of degradation such as wear, missing parts, holes, and clearances. Functional/operational condition tests of fire doors are also conducted. In the program basis document, PBD-AMP-B.1.19 and in its response to an audit question, the applicant further stated that enhancements to the program will direct visual inspection of fire doors for integrity of door surfaces and clearance checks every two years. This inspection frequency ensures the timely identification and correction of degraded door conditions prior to a loss of intended function. The project team determined that visual inspection of fire doors for signs of degradation such as wear, missing parts, holes, and clearances will provide additional assurance that the effects of aging are adequately managed, as recommended in the GALL Report; therefore, this enhancement is acceptable.

On this basis, the project team found this enhancement acceptable since when the enhancement is implemented, OCGS AMP B.1.19, "Fire Protection,” will be consistent with GALL AMP XI.M26 and will provide additional assurance that the effects of aging will be adequately managed.

3.0.3.2.16.5 Operating Experience

In the OCGS LRA, the applicant stated that the fire protection aging management program has been effective in identifying aging effects and taking appropriate corrective action. Minor degradation such as minor cracks have been detected in concrete components in structures within the scope of license renewal. The observed degradation was evaluated and dispositioned based on program acceptance criteria and in accordance with the corrective action process. The applicant's experience with fire barrier penetration seals is consistent with the industry experience; silicone foam fire barrier penetration seals are used at Oyster Creek. The applicant stated that it has experienced fire door component degradation due to wear, loss of material due to corrosion, and physical damage and mitigating actions have been taken as appropriate.

In the OCGS LRA, the applicant stated that operating experience has shown no loss of material on the external surfaces of components in the halon and carbon dioxide systems that have adversely affected system operation.

In the OCGS LRA, the applicant also stated that the diesel-driven fire pump fuel oil systems have experienced minor system events that have been detected and corrected in a timely manner. These events were identified and corrected prior to loss of intended function of the fire pumps. There have been no reports of loss of material or flow blockage of the fuel oil subsystems.

In its program basis document for the fire protection aging management program (PDB-AMP-B.1.19), the applicant stated that operating experience, both internal and external, is used to enhance plant programs, prevent repeat events, and prevent events that have occurred at other plants from occurring at Oyster Creek. Through its operating experience review process the applicant screens, evaluates, and acts on operating experience documents and information to prevent or mitigate the consequences of similar events. In addition, the applicant stated that its process for managing programs requires the review of program-related operating experience by the program owner. Both of these processes review operating experience from both external and internal (also referred to as in-house) sources. External operating experience may include items such as INPO documents (e.g., SOERs, SERs, SENs, etc.), NRC documents (e.g., GLs, LERs, INs, etc.), General Electric documents (e.g., RCSILs, SILs, TILs, etc.), and other documents (e.g., 10CFR Part 21 Reports, NERs, etc.). Internal operating experience may include documents such as event investigations, trending reports, and lessons learned from in-house events as captured in program notebooks, self-assessments, and in the 10 CFR Part 50, Appendix B corrective action process. Issues and events, whether external or plant-specific, that are potentially significant to the fire protection program at OCGS are evaluated. The fire protection program is augmented, as appropriate, if these evaluations show that program changes are needed to enhance program effectiveness. The corrective actions program ensures that the conditions adverse to quality are promptly corrected. If the deficiency is assessed to be significantly adverse to quality, the cause of the condition is determined and a corrective action plan is developed to preclude repetition.

In the OCGS LRA, the applicant stated that the fire protection program has been effective in identifying aging effects and taking appropriate corrective action. In its program basis document (PDB-AMP-B.1.19) the applicant further stated that the operating experience of fire protection program did not show any adverse trends in performance, those problems identified would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence.

The project team reviewed the operating experience provided in the OCGS LRA and the program basis document (PDB-AMP-B.1.19), and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience. The fire protection aging management program activities with enhancements described above will be effective in managing aging degradation for the period of extended operation by providing timely detection of aging effects and implementing appropriate corrective actions prior to loss of system or component intended functions.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant’s fire protection program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.2.16.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the fire protection program in OCGS LRA, Appendix A, Section A.1.19, which stated that the fire protection aging management program is an existing program that includes a fire barrier inspection program and a diesel-driven fire pump inspection program. The fire barrier inspection program requires periodic visual inspection of fire barrier penetration seals, fire wraps, fire barrier walls, ceilings, and floors, and periodic visual inspection and functional tests of fire rated doors to ensure that their operability is maintained. The program includes surveillance tests of fuel oil systems for the diesel-driven fire pumps to ensure that the fuel supply lines can perform intended functions. The program also includes visual inspections and periodic operability tests of halon and carbon dioxide fire suppression systems based on NFPA codes.

In the UFSAR Supplement for the fire protection program in OCGS LRA, Appendix A, Section A.1.19, the applicant stated that prior to the period of extended operation the fire protection aging management program will be enhanced to include:

1. Specific fuel supply inspection criteria for fire pumps during tests
2. Inspection of external surfaces of the halon and carbon dioxide fire suppression systems
3. Additional inspection criteria for degradation of fire barrier walls, ceilings, and floors

The project team also reviewed the applicant’s license renewal commitment list in Appendix A of the OCGS LRA, and confirmed that the enhancements to this program are identified and will be implemented prior to the period of extended operation as item 19 of the commitments.

In its letter dated April 17, 2006 (ML061150320), the applicant committed to revise AMP B.1.19 in the OCGS LRA to add the enhancement discussed in the program basis document, PBD-AMP-B.1.19, to require periodic visual inspections of fire door surface integrity and clearance checks. This is **Audit Commitment 3.0.3.2.16-1.** The applicant’s license renewal commitment list and UFSAR supplement are to be revised to reflect this new commitment.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.19. Contingent upon the inclusion of commitment 3.0.3.2.16-1, the project team found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.2.16.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report, are consistent with the GALL Report. In addition, the project team has reviewed the exception and the associated justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. Also, the project team has reviewed the enhancements and determined that the implementation of the enhancements prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The project team also reviewed the UFSAR Supplement for this AMP and, contingent upon the inclusion of commitment 3.0.3.2.16-1, found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.17 Fire Water System (OCGS AMP B.1.20)

In OCGS LRA, Appendix B, Section B.1.120, the applicant stated that OCGS AMP B.1.20, "Fire Water System," is an existing plant program that is consistent with GALL AMP XI.M27, "Fire Water System," with enhancements.

3.0.3.2.17.1 Program Description

In the OCGS LRA, the applicant stated that this program will manage identified aging effects for the water-based fire protection system and associated components, through the use of periodic inspections, monitoring, and performance testing. The program includes preventive measures and inspection activities to detect aging effects prior to loss of intended functions. System functional tests, flow tests, flushes and inspections are performed in accordance with guidance from NFPA standards. Fire system main header flow tests are conducted at least once every three years. Hydrant flushing and inspections are conducted at least once every twelve months. The condition of the fire pumps is confirmed once every 18 months by performance of a pump functional test. The redundant water storage tank is inspected once every 5 years. Sprinkler system inspections are performed at least once every refueling outage. The fire water system is maintained at the required normal operating pressure and monitored such that a loss of system pressure is immediately detected and corrective actions initiated. Periodic water samples will be tested to detect the presence of MIC. The program will be enhanced to include volumetric inspections using appropriate techniques on system piping to monitor pipe wall thickness and evaluate internal pipe conditions. The system flow testing, visual inspections and volumetric inspections assure that the aging effects of reduction of heat transfer and loss of material due to corrosion, MIC, or biofouling are managed such that the system intended functions are maintained.

3.0.3.2.17.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.20 is consistent with GALL AMP XI.M27, with enhancements.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.20, including program basis document, PBD-AMP-B.1.20, ?Fire Water System," Rev. 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M27. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.20 and associated bases documents to determine consistency with GALL AMP XI.M27.

The project team also reviewed the applicant's procedure 101.2, Rev. 54, ?Oyster Creek Site Fire Protection Program," and procedure CC-AA-211, Rev. 1, ?Fire Protection Program," to determine consistency with GALL AMP XI.M24.

The project team reviewed those portions of the fire water system program for which the applicant claims consistency with GALL AMP XI.M27 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's fire water system program conforms to the recommended GALL AMP XI.M27, "Fire Water System,"with the enhancements described below.

3.0.3.2.17.3 Exceptions to the GALL Report

None.

3.0.3.2.17.4 Enhancements

In the OCGS LRA, the applicant identified the following enhancements in order to meet the GALL Report program elements:

Enhancement 1

Elements: 2. Preventive Actions
3. Parameters Monitored or Inspected
4. Detection of Aging Effects
5. Monitoring and Trending
6. Acceptance Criteria

Enhancement: The fire water system aging management program will be enhanced to include periodic non-intrusive wall thickness measurements of selected portions of the fire water system at intervals that do not exceed every 10 years.

The GALL Report identified the following recommendations for the ?preventive actions," ?parameters monitored or inspected," ?detection of aging effects," ?monitoring and trending," and ?acceptance criteria" program elements associated with the enhancement:

2. *Preventive Actions*: To ensure no significant corrosion, MIC, or biofouling has occurred in water-based fire protection systems, periodic flushing, system performance testing, and inspections may be conducted.

3. *Parameters Monitored or Inspected*: Loss of material due to corrosion and biofouling could reduce wall thickness of the fire protection piping system and result in system failure. Therefore, the parameters monitored are the system's ability to maintain pressure and internal system corrosion conditions. Periodic flow testing of the fire water system is performed using the guidelines of NFPA 25, or wall thickness evaluations may be performed to ensure that the system maintains its intended function.

4. *Detection of Aging Effects*: Wall thickness evaluations of fire protection piping are performed on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion.

5. *Monitoring and Trending*: Degradation identified by non-intrusive or internal inspection is evaluated.

6. *Acceptance Criteria*: No unacceptable signs of degradation observed during non-intrusive or visual assessment of internal system conditions.

In reviewing this enhancement, the project team noted that the applicant's fire water system aging management program will manage identified aging effects for the water-based fire protection system and associated components, through the use of periodic inspections, monitoring, and performance testing. The program includes preventive measures and inspection activities to detect aging effects prior to loss of intended functions. System functional tests, flow tests, flushes and inspections are performed in accordance with guidance from NFPA standards. This enhancement will add volumetric inspections using appropriate techniques on system piping to monitor pipe wall thickness and evaluate internal pipe conditions, as recommended in the GALL Report. Since the addition of non-intrusive wall thickness measurements of selected portions of the fire water system will provide additional assurance that the effects of aging will be adequately managed, the project team determined that this enhancement is acceptable.

On this basis, the project team found this enhancement acceptable since when the enhancement is implemented, OCGS AMP B.1.20, "Fire Water System," will be consistent with GALL AMP XI.M27 and will provide additional assurance that the effects of aging will be adequately managed.

<u>Enhancement 2</u>

Element:	2. Preventive Actions
Enhancement:	The fire water system aging management program will be enhanced to include periodic water sampling of the fire water system for the presence of MIC, at intervals not to exceed every 5 years

The GALL Report identified the following recommendation for the ?Preventive Actions" program element associated with the enhancement:

2. *Preventive Actions*: To ensure no significant corrosion, MIC, or biofouling has occurred in water-based fire protection systems, periodic flushing, system performance testing, and inspections may be conducted.

In reviewing this enhancement, the project team noted that the applicant's fire water system aging management program includes preventive actions to preclude buildup of significant corrosion, MIC or biofouling by providing for periodic flushing, system performance testing, and inspections to identify these degraded conditions prior to loss of system intended function. This enhancement will add water sampling for the presence of MIC every 5 years, as recommended in the GALL Report. Since the addition of water sampling for the presence of MIC will provide additional assurance that the effects of aging will be adequately managed, the project team determined that this enhancement is acceptable.

On this basis, the project team found this enhancement acceptable since when the enhancement is implemented, OCGS AMP B.1.20, "Fire Water System," will be consistent with GALL AMP XI.M27 and will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 3

Element: 4. Detection of Aging Effects

Enhancement: The fire water system aging management program will be enhanced to include inspection of sprinkler heads before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner.

The GALL Report identified the following recommendation for the ?Detection of Aging Effects" program element associated with the enhancement:

> 4. *Detection of Aging Effects*: Sprinkler heads are inspected before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner.

In reviewing this enhancement, the project team noted that the applicant's fire water system aging management program will manage identified aging effects for the water-based fire protection system and associated components, through the use of periodic inspections, monitoring, and performance testing. The program includes preventive measures and inspection activities to detect aging effects prior to loss of intended functions. System functional tests, flow tests, flushes and inspections are performed in accordance with guidance from NFPA standards. Sprinkler system inspections are performed at least once every refueling outage. This enhancement will include 50-year sprinkler head inspections using the guidance of NFPA 25 ?Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems" (1998 Edition), Section 2-3.1.1. Representative samples will be submitted to a testing laboratory prior to being in service 50 years. Thereafter, this testing will be repeated on a frequency of once every 10 years during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner. Initial inspections will be performed prior to the sprinkler heads being in service for 50 years. Since the addition of 50-year sprinkler head inspections will provide additional assurance that the effects of aging are adequately managed, the project team determined that this enhancement is acceptable.

On this basis, the project team found this enhancement acceptable since when the enhancement is implemented, OCGS AMP B.1.20, "Fire Water System," will be consistent with GALL AMP XI.M27 and will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 4

Element: 1. Program Scope

Enhancement: The fire water system aging management program will be enhanced to include visual inspection of the redundant fire water storage tank heater during tank internal inspections.

The GALL Report identified the following recommendation for the ?program scope" program element associated with the enhancement:

> 1. *Program Scope*: The AMP focuses on managing loss of material due to corrosion, MIC, or biofouling of carbon steel and cast iron components in fire protection systems exposed to water.

In reviewing this enhancement, the project team noted that the applicant's fire water system aging management program will manage identified aging effects for the water-based fire protection system and associated components, through the use of periodic inspections, monitoring, and performance testing. The program includes preventive measures and inspection activities to detect aging effects prior to loss of intended functions. System functional tests, flow tests, flushes and inspections are performed in accordance with guidance from NFPA standards. The redundant water storage tank is inspected once every five years. This enhancement will include visual inspection of the redundant fire water storage tank heater during tank internal inspections, as recommended in the GALL Report. Since visual inspection of the redundant fire water storage tank heater will provide additional assurance that the effects of aging are adequately managed, the project team determined that this enhancement is acceptable.

In reviewing the program basis document, PBD-AMP-B.1.20, the audit team noted that Section 2.4, ?Summary of Enhancements to NUREG-1801," states that the Oyster Creek fire water system aging management program will be enhanced to include visual inspection of the water storage tank heater pressure boundary components during the periodic tank internal inspections. However, this enhancement was not identified or discussed in the Section 3.0 evaluation of the individual GALL aging management program elements. During the audit, the applicant stated that PBD-AMP-B.1.20 will be revised to include this enhancement in the program basis document Section 3.1, ?scope of program".

The applicant stated that the program basis document for AMP B.1.20, fire water system, will be revised to add the enhancement for visual inspection of the water storage tank heater pressure boundary components during the periodic tank internal inspections to the ?scope of program" element of the program.

On this basis, the project team found this enhancement acceptable since when the enhancement is implemented, OCGS AMP B.1.20, "Fire Water System," will be consistent with GALL AMP XI.M27 and will provide additional assurance that the effects of aging will be adequately managed.

3.0.3.2.17.5 Operating Experience

In the OCGS LRA, the applicant stated that the fire water system aging management program has been effective in identifying aging effects and taking appropriate corrective action. In 2002, a hydrant was identified with significant leakage below ground when operated. The problem was discovered during the hydrant flush surveillance activity. The hydrant was declared inoperable, but did not affect the rest of the system and was also considered available for use in an emergency. The hydrant was replaced with a new hydrant. In 2003, a leak was discovered in a small diameter cooling water line associated with the #2 diesel-driven fire pump. A failure analysis performed on a sample of the failed piping determined that turbulent flow downstream of a 90˚ elbow tended to remove corrosion product buildup, and that constant removal of corrosion product buildup would expose fresh metal leading to accelerated attack. The preferential attack identified on the bottom of the pipe suggests the attack might have been influenced by incomplete drainage following pump operation. The resulting stagnant lay-up of fresh water provides a favorable condition for MIC attack. The condition created pin-hole leaks which have been repaired. As a result of this failure, NDE inspections were performed at piping locations subject to similar conditions. Some additional small bore wall thinning has been identified, and is being tracked for repair and replacement. The applicant stated in the LRA that pump performance testing, hydrant inspection activities, and the corrective action process identified and corrected these degraded conditions prior to a loss of fire protection system intended functions.

In its program basis document (PDB-AMP-B.1.20) the applicant stated that the fire water system is designed, inspected, tested and maintained in accordance with the applicable NFPA minimum standards. The applicant further stated that operating experience, both internal and external, is used to enhance plant programs, prevent repeat events, and prevent events that have occurred at other plants from occurring at Oyster Creek. Through its operating experience review process the applicant stated that it screens, evaluates, and acts on operating experience documents and information to prevent or mitigate the consequences of similar events. In addition, the applicant stated that its process for managing programs requires the review of program related operating experience by the program owner. Both of these processes review operating experience from both external and internal (also referred to as in-house) sources. External operating experience may include such things as INPO documents (e.g., SOERs, SERs, SENs, etc.), NRC documents (e.g., GLs, LERs, INs, etc.), General Electric documents (e.g., RCSILs, SILs, TILs, etc.), and other documents (e.g., 10CFR Part 21 Reports, NERs, etc.). Internal operating experience may include such things as event investigations, trending reports, and lessons learned from in-house events as captured in program notebooks, self-assessments, and in the 10 CFR Part 50, Appendix B corrective action process. Issues and events, whether external or plant-specific, that are potentially significant to the fire water system aging management program at OCGS are evaluated. The fire water system aging management program is augmented, as appropriate, if these evaluations show that program changes are needed to enhance program effectiveness. The corrective actions program ensures that the conditions adverse to quality are promptly corrected. If the deficiency is assessed to be significantly adverse to quality, the cause of the condition is determined and a corrective action plan is developed to preclude repetition.

In its program basis document (PBD-AMP- B.1.20) the applicant further stated that its review of operating experience of the fire water system aging management program did not show any adverse trend in fire water system performance. Problems identified did not cause a loss of the system intended function, and adequate corrective actions were taken to prevent recurrence.

The project team reviewed the operating experience provided in the OCGS LRA, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience. The fire water system aging management program activities, with enhancements described above, will be effective in managing aging degradation for the period of extended operation by providing timely detection of aging effects and implementing appropriate corrective actions prior to loss of system or component intended functions.

On the basis of its review of the above industry and plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant's fire water system program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.2.17.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the fire water system program in OCGS LRA, Appendix A, Section A.1.20, which states that the fire water system program is an existing program that provides for system pressure monitoring, fire system header flow testing, pump performance testing, hydrant flushing, water sampling and visual inspections activities. System flow tests measure hydraulic resistance and compare results with previous testing, as a means of evaluating the internal piping conditions. Monitoring system piping flow characteristics ensures that signs of internal piping degradation from significant corrosion or fouling would be detected in a timely manner. Pump performance tests, hydrant flushing and system inspections are performed in accordance with applicable NFPA standards. A motor driven pump normally maintains fire water system pressure. Significant leakage (exceeding the capacity of this pump) would be identified by automatic start of the diesel driven fire pumps, which would initiate immediate investigation and corrective action.

The applicant further stated in the LRA that the fire water system aging management program will be enhanced to include sprinkler head testing in accordance with NFPA 25, ?Inspection, Testing and Maintenance of Water-Based Fire Protection Systems." Samples will be submitted to a testing laboratory prior to being in service 50 years. This testing will be repeated at intervals not exceeding 10 years. Prior to the period of extended operation, the program will be enhanced to include water sampling for the presence of MIC at an interval not to exceed 5 years, periodic non-intrusive wall thickness measurements of selected portions of the fire water system at an interval not to exceed every 10 years, and visual inspection of the redundant fire water storage tank heater during tank internal inspections.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.20, and found that it was consistent with the GALL Report. The project team determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.2.17.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report, are consistent with the GALL Report. Also, the project team has reviewed the enhancements and determined that the implementation of the enhancements prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The project team also reviewed the UFSAR Supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.18 Aboveground Outdoor Tanks (OCGS AMP B.1.21)

In OCGS LRA, Appendix B, Section B.1.21, the applicant stated that OCGS AMP B.1.21, "Aboveground Outdoor Tanks," is a new plant program that is consistent with GALL AMP XI.M29, "Aboveground Carbon Steel Tanks," with an exception.

3.0.3.2.18.1 Program Description

The applicant stated, in the OCGS LRA, that this program will provide for management of loss of material aging effects for outdoor carbon steel and aluminum storage tanks. The program credits the application of paint as a corrosion preventive measure and performs periodic visual inspections to monitor degradation of the paint and any resulting metal degradation for the carbon steel tanks. The program will include periodic visual inspections of the aboveground aluminum tank. Periodic internal UT inspections will be performed on the bottom of outdoor carbon steel tanks and the outdoor aluminum storage tank supported by earthen/concrete foundations. The carbon steel tanks not directly supported by earthen or concrete foundations undergo external visual inspections without the necessity of bottom surface UT inspections.

The applicant also stated that the tanks supported by earthen/concrete foundations having sealants/coatings at the tank-foundation interfaces will be periodically inspected for degradation. For raised tanks not directly supported by earthen or concrete foundations, inspection of the sealant or caulking at the tank-foundation interface does not apply.

The program will require removal of insulation to permit visual inspection of insulated tank surfaces. Removal of insulation will be on a sampling basis.

The applicant further stated that the program will be implemented prior to the period of extended operation. Tanks will be inspected at an initial frequency of every five years.

3.0.3.2.18.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.21 is consistent with GALL AMP XI.M29, with an exception.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.21, including program basis document OCGS PBD-AMP B.1.21, "Aboveground Outdoor Tanks," Revision 1, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M29. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.21 and associated bases documents to determine consistency with GALL AMP XI.M29.

The project team also reviewed OCGS documents SP-1302-52-108, ?Inspection of Tanks," Revision 3, and MA-AA-716-210, ?Performance Centered Maintenance Process," Revision 2, that provided guidance regarding the aboveground tanks program and the tanks ranking and schedule for inspection.

The project team reviewed those portions of the aboveground outdoor tanks program for which the applicant claims consistency with GALL AMP XI.M29 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's aboveground outdoor tanks program conforms to the recommended GALL AMP XI.M29, with the exceptions described below.

3.0.3.2.18.3 Exceptions to the GALL Report

In the OCGS LRA, the applicant stated the following exception to the GALL Report program elements:

Exception 1

Elements:	1. Scope of Program 2. Preventive Actions
Exception :	The Oyster Creek program includes inspection of the outdoor aluminum storage tanks. Due to corrosion resistance properties of aluminum, these tanks are not painted.

The GALL Report identified the following recommendations for the above program elements associated with the exception taken:

> 1. *Scope of Program*: The program consists of (a) preventive measures to mitigate corrosion by protecting the external surfaces of carbon steel tanks protected with paint or coatings and (b) periodic system walkdowns to manage the effects of corrosion on the intended function of these tanks. Plant walkdowns cover the entire outer surface of the tank up to its surface in contact with soil or concrete.
>
> 2. *Preventive Actions*: In accordance with industry practice, tanks are coated with protective paint or coating to mitigate corrosion by protecting the external surface of the tank from environmental exposure.

The applicant stated, in the OCGS LRA, that the Oyster Creek program includes the outdoor aluminum storage tanks in addition to the carbon steel tanks. Due to corrosion resistance properties of aluminum, the tanks are not painted. For aluminum tanks, the aging management program includes visual inspections, sealants/coating examination at the tank foundation interfaces, and periodic UT inspections on the tank bottom. On the basis of its review of operating experience for the aboveground outdoor tanks program (see Section 3.0.3.2.18.5, below), the project team found this exception to be acceptable since the exception appropriately adds aluminum tanks to the scope of the aging management program.

The project team reviewed this exception and concluded that it is acceptable to include aluminum tanks in this program because it adds aluminum tank within the scope of the AMP. The staff finds that it is also acceptable to not paint aluminum tanks because experience has shown that aluminum does not rust when exposed to atmospheric conditions.

In the program basis document, the applicant stated the following exception to the GALL Report program elements:

Exception 2

Element:	5. Monitoring and Trending

Exception: The specified frequency by the Oyster Creek program is every 5 years in place of system walkdowns each outage.

The GALL Report identified the following recommendations for the above program elements associated with the exception taken:

> 5. *Monitoring and Trending*: The effects of corrosion of the aboveground external surface are detectable by visual techniques. Based on operating experience, plant system walkdowns during each outage provide for timely detection of aging effects.

The applicant stated, in the program basis document, the frequency of 5 years specified for monitoring of exterior surfaces of tanks is consistent with the frequency specified for exterior surfaces of supporting structures. The 5 year frequency is consistent with industry guidelines and has proven effective in detecting loss of material due to corrosion, and change in material properties of structural elastomers on exterior surfaces of structures. Consequently this frequency will also be effective for detecting loss of material and change in material properties on exterior surfaces of tank before an intended function is impacted.

The project team questioned the schedule for conducting the walkdowns and asked if the schedule is consistent with the GALL recommendation. The applicant stated that they use structured inspections every five years rather than system walkdowns every outage and that this is an exception to the GALL recommendation. The applicant stated that the inspection frequency is consistent with the practical life of the coatings and the industry application of the structures monitoring programs in response to the Maintenance Rule. The project team found this exception to GALL to be acceptable, because it meets the requirements of the Maintenance Rule. However, the project team noted that the applicant has not identified this exception in the OCGS LRA.

In its letter dated April 17, 2006 (ML061150320), the applicant committed to revise the aboveground outdoor tanks program (B.1.21) in the OCGS LRA to include the exception identified in the program basis document, which states that the specified frequency by the Oyster Creek program is every 5 years in place of system walkdowns each outage. **This is Audit Commitment 3.0.3.2.18-1.**

On the basis of its review of operating experience for the Aboveground Outdoor Tanks program (see Section 3.0.3.2.18.5, below), the project team found this exception to be acceptable based on industry experience and operating experience.

3.0.3.2.18.4 Enhancements

None.

3.0.3.2.18.5 Operating Experience

The applicant stated, in the OCGS LRA and the program basis document, that the aboveground outdoor tank inspection program is a new program being implemented at Oyster Creek, and therefore, no program experience exists. It will replace selective inspections and will complement those activities in place for tank management of petroleum and other hazardous aboveground and buried tanks. The program is based on industry guidance and the GALL program for aboveground carbon steel tanks. However, specific plant experience does exist. Corrosion of the condensate storage tank was previously detected.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant's aboveground outdoor tanks program will adequately manage the aging effects that are identified in OCGS LRA for which this AMP is credited during the period of extended operation.

The project team reviewed the operating experience provided in the OCGS LRA, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

The staff believes that the corrective action process will capture internal and external plant operating issues to ensure that aging effects are adequately managed.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant's aboveground outdoor tanks program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.2.18.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the Aboveground Outdoor Tanks program in OCGS LRA, Appendix A, Section A.1.21, which stated that the Aboveground Outdoor Tanks program is a new program that will manage corrosion of outdoor carbon steel and aluminum tanks. Paint is a corrosion preventive measure, and periodic visual inspections of the exterior surface will monitor degradation of the paint and any resulting metal degradation of carbon steel tanks or the unpainted aluminum tank. In scope carbon steel tanks are both supported by structural steel and by earthen or concrete foundations. The aluminum tank is supported by an earthen foundation. Therefore, inspection of the sealant or caulking at the tank-foundation interface, and UT inspection of inaccessible tank locations such as on-grade tank bottoms apply only to those tanks on earthen and concrete pads. UT inspections will also be performed on the tank-foundation where caulking or sealants are used. Removal of insulation will permit visual inspection of insulated tank surfaces and caulking. This new inspection program will be implemented prior to the period of extended operation.

The project team also reviewed the applicant's license renewal commitment list in Appendix A of the OCGS LRA, and confirmed that this program is identified as a new program that will be implemented prior to the period of extended operation as item 21 of the commitments.

As stated in Audit Commitment 3.0.3.2.18-1, the applicant committed to revise the aboveground outdoor tanks program (B.1.21) in the OCGS LRA to include the exception identified in the program basis document, which states that the specified frequency by the Oyster Creek program is every 5 years in place of system walkdowns each outage. The applicant's license renewal commitment list and UFSAR supplement are to be revised to reflect this new commitment.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.21. Contingent upon the inclusion of Audit Commitment 3.0.3.2.18.1, the project team found that it was consistent with the GALL Report. The project team determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.2.18.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report, are consistent with the GALL Report. In addition, the project team has reviewed the exception and the associated justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. The project team also reviewed the UFSAR Supplement for this AMP and, contingent upon the inclusion of Audit Commitment 3.0.3.2.18.1, found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.19 Fuel Oil Chemistry (OCGS AMP B.1.22)

In the OCGS LRA, Appendix B, Section B.1.22, the applicant stated that OCGS AMP B.1.22, "Fuel Oil Chemistry," is an existing plant program that is consistent with GALL AMP XI.M30, "Fuel Oil Chemistry," with exceptions and enhancements.

3.0.3.2.19.1 Program Description

In the OCGS LRA, the applicant stated that this program's activities are preventive activities that provide assurance that contaminants are maintained at acceptable levels in fuel oil for systems and components within the scope of license renewal. The fuel oil tanks within the scope of license renewal are maintained by monitoring and controlling fuel oil contaminants in accordance with the guidelines of the American Society for Testing and Materials (ASTM). Fuel oil sampling activities meet the intent of ASTM D 4057-95 (2000). Fuel oil will be routinely sampled and analyzed for particulates in accordance with modified ASTM Standard D 2276-00 Method A, and for the presence of water and sediment in accordance with ASTM Standard D 2709-96. Fuel oil sampling and analysis are performed in accordance with approved procedures for new fuel and stored fuel. Fuel oil tanks are periodically drained of accumulated water and sediment, and will be periodically drained, cleaned, and internally inspected. These activities effectively manage the effects of aging by providing reasonable assurance that potentially harmful contaminants are maintained at low concentrations.

3.0.3.2.19.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.22 is consistent with GALL AMP XI.M30, with exceptions and enhancements.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.22, including basis document PBD-AMP-B.1.22, ?Fuel Oil Chemistry," Revision 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M30. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.22 and associated bases documents to determine their consistency with GALL AMP XI.M30.

In reviewing this AMP, the project team noted that the program description in the OCGS LRA for AMP B.1.22 stated that fuel oil will be routinely sampled and analyzed for particulates and for the presence of water and sediment; however, the frequency of these activities was not discussed. The applicant was asked to provide the frequency of these activities.

In its response, the applicant stated that the sample frequencies, sample locations, and acceptance criteria are included in OCGS procedure 828.7, ?Secondary Systems Analysis: Plant Oil." All analysis frequencies are quarterly or more frequent, in accordance with NUREG-1801, AMP XI.M30, which states in program element 5 that based on industry operating experience, quarterly sampling and analysis of fuel oil provide for timely detection of conditions conducive to corrosion. The project team reviewed OCGS procedure 828.7, as well as GALL AMP XI.M30, which confirmed that the applicant's sampling frequency is consistent the recommendations in the GALL Report. On this basis, the project team determined that the applicant's sampling frequency was acceptable.

The project team further noted that the program description in the OCGS LRA for AMP B.1.22 states that fuel oil tanks are periodically drained of accumulated water and sediment, and will be periodically drained, cleaned, and internally inspected. However, the tanks on which these activities would be performed were not identified. The applicant was asked to provide additional information on the tanks included in the scope of these activities.

In its response, the applicant stated that the following implementing activities address the periodic draining of accumulated water and sediment:

- Recurring task work order R0801584 (T-9-103, fire pond diesel fuel oil storage tank ?A") is performed quarterly.

- Recurring task work order R0801586 (T-9-104, fire pond diesel fuel oil storage tank ?B") is performed quarterly.

- Recurring task work order R2045449 (T-36-1, fuel oil storage tank) is performed quarterly.

- Recurring task work order R2044252 (T-39-2, diesel generator fuel oil storage tank) is performed quarterly.

The applicant further stated that the following implementing activities address the periodic draining, cleaning, and internal inspection:

- Recurring task work order R2060569 (T-9-103, fire pond diesel fuel oil storage tank ?A") will be performed every 5 years based on the ?Tanks" maintenance template, criticality determination, duty cycle, and service condition.

- Recurring task work order R2060570 (T-9-104, fire pond diesel fuel oil storage tank ?B") will be performed every 5 years based on the ?Tanks" maintenance template, criticality determination, duty cycle, and service condition.

- Recurring task work order Rxxxxx(new) (T-36-1, main fuel oil storage tank) will be performed every 10 years based on the ?Tanks" maintenance template, criticality determination, duty cycle, and service condition

- Recurring task work order R2042556 (T-39-2, diesel generator fuel oil storage tank) is currently performed every 10 years based on the ?Electro-Motive Division Diesel Generator" maintenance template, criticality determination, duty cycle, and service condition.

The applicant further stated that the EDG fuel oil storage tank (T-39-2) was last opened, cleaned, and inspected in October/November 2004.

The applicant was asked when the draining, cleaning, and inspection of the main fuel oil storage tank and the fire pond diesel fuel oil tanks would be initiated. In its response, the applicant stated that the tasks for draining, cleaning, and internally inspecting these tanks will be performed prior to the period of extended operation.

Based on the applicant's responses, the project determined that all of the major fuel oil tanks at OCGS will be drained of water and sediment on a quarterly basis, which is reasonable to minimize contact time with the tank bottom. Further, the fire pond diesel fuel oil storage tanks will be drained, cleaned, and internally inspected every 5 years, and the main fuel oil storage tank and the EDG fuel oil storage tank will be drained, cleaned, and inspected every 10 years, which is reasonable to ensure that aging degradation is adequately managed. The performance of these activities on a periodic basis is consistent with the recommendations in the GALL Report. These activities will be performed prior to the period of extended operation. The only fuel oil tanks not included in these activities are the diesel generator day tanks, and they are addressed in a program exception, which is discussed below. On this basis, the project team determined that the applicant's program activities for draining water and sediment, as well as for draining, cleaning, and inspecting the fuel oil storage tanks are acceptable.

The project team reviewed those portions of the fuel oil chemistry program for which the applicant claimed consistency with GALL AMP XI.M30 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's fuel oil chemistry program conforms to the recommended GALL AMP XI.M30, "Fuel Oil Chemistry," with the exceptions and enhancements described below.

3.0.3.2.19.3 Exceptions to the GALL Report

In the OCGS LRA, the applicant stated the following exceptions to the GALL Report program elements:

Exception 1:

Elements:	1. Scope of Program 2. Preventive Actions 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring and Trending 6. Acceptance Criteria
Exception:	NUREG-1801 indicates that fuel oil tanks should be sampled for water and sediment, biological activity, and particulate on a periodic basis, and that multilevel sampling of tanks should be performed. Multilevel sampling and tank bottom sampling of the Emergency Diesel Generator (EDG) Day Tanks are not routinely performed at Oyster Creek. The EDG Day Tanks do not have the capability of being sampled, however, these tanks are supplied directly from the EDG Fuel Storage Tank, which is routinely sampled and analyzed. The EDG Day Tanks are small in size and experience a high turnover rate of the fuel stored within as a

result of routine engine operations. Stratification of fuel is not likely to occur in the EDG Day Tanks due to the high turnover rate. Additionally, the Emergency Diesel Generator Day Tanks are skid mounted on the Emergency Diesel Generator skid and are enclosed within the diesel enclosure, which is maintained at a constant temperature during cold periods through operation of the Emergency Diesel Generator keepwarm system. Maintaining a constant temperature during cold periods minimizes Emergency Diesel Generator Day Tank thermal cycling and reduces the potential for condensation formation within the Day Tanks. The routine draining of water and sediment from the bottom of the Day Tanks is therefore not necessary.

The GALL Report identifies the following recommendations for the ?scope of program," ?preventive actions," ?parameters monitored or inspected," ?detection of aging effects," ?monitoring and trending," and ?acceptance criteria" program elements associated with the exception taken:

1. *Scope of Program:* The program is focused on managing the conditions that cause general, pitting, and MIC of the diesel fuel tank internal surfaces in accordance with the plant's technical specifications (i.e., NUREG- 1430, NUREG-1431, NUREG-1432, NUREG-1433) on fuel oil purity and the guidelines of ASTM Standards D1796, D2276, D2709, D6217, and D4057. The program serves to reduce the potential of exposure of the tank internal surface to fuel oil contaminated with water and microbiological organisms.

2. *Preventive Actions:* The quality of fuel oil is maintained by additions of biocides to minimize biological activity, stabilizers to prevent biological breakdown of the diesel fuel, and corrosion inhibitors to mitigate corrosion. Periodic cleaning of a tank allows removal of sediments, and periodic draining of water collected at the bottom of a tank minimizes the amount of water and the length of contact time. Accordingly, these measures are effective in mitigating corrosion inside diesel fuel oil tanks. Coatings, if used, prevent or mitigate corrosion by protecting the internal surfaces of the tank from contact with water and microbiological organisms.

3. *Parameters Monitored or Inspected:* The AMP monitors fuel oil quality and the levels of water and microbiological organisms in the fuel oil, which cause the loss of material of the tank internal surfaces. The ASTM Standard D 4057 is used for guidance on oil sampling. The ASTM Standards D 1796 and D 2709 are used for determination of water and sediment contamination in diesel fuel. For determination of particulates, modified ASTM D 2276, Method A, is used. The modification consists of using a filter with a pore size of 3.0 mm, instead of 0.8 mm. These are the principal parameters relevant to tank structural integrity.

4. *Detection of Aging Effects:* Degradation of the diesel fuel oil tank cannot occur without exposure of the tank internal surfaces to contaminants in the fuel oil, such as water and microbiological organisms. Compliance with diesel fuel oil standards in item 3, above, and periodic multilevel sampling provide assurance that fuel oil contaminants are below unacceptable levels. Internal surfaces of tanks that are drained for cleaning are visually inspected to detect potential degradation. However, corrosion may occur at locations in which contaminants may accumulate, such as a tank bottom, and an ultrasonic

thickness measurement of the tank bottom surface ensures that significant degradation is not occurring.

5. *Monitoring and Trending:* Water and biological activity or particulate contamination concentrations are monitored and trended in accordance with the plant's technical specifications or at least quarterly. Based on industry operating experience, quarterly sampling and analysis of fuel oil provides for timely detection of conditions conducive to corrosion of the internal surface of the diesel fuel oil tank before the potential loss of its intended function.

6. *Acceptance Criteria:* The ASTM Standard D 4057 is used for guidance on oil sampling. The ASTM Standards D 1796 and D 2709 are used for guidance on the determination of water and sediment contamination in diesel fuel. ASTM D 6217 and Modified D 2276, Method A are used for guidance for determination of particulates. The modification to D 2276 consists of using a filter with a pore size of 3.0 mm, instead of 0.8 mm.

The project team noted that, as part of the justification for this exception, the OCGS LRA stated that the EDG day tanks experience a high turnover rate of fuel, and that stratification of the fuel is not likely to occur due to this high turnover rate. The applicant was asked to provide additional information as to what the day tank fuel turnover rate is and the basis for concluding that stratification would not occur.

In its response, the applicant stated that the EDG day tanks are small in size (130 gallons) and experience a high turnover rate of the fuel stored within as a result of routine engine operations. During diesel generator load testing, approximately 200 gallons of fuel oil will be consumed (approximately 1 hour of operation at 200 gallons per hour). Depending on the day tank level (normal level is above 1/4 full), the day tank contents may turnover multiple times during load testing, which is performed every 14 days. Stratification of fuel is not likely to occur in the EDG day tanks due to this high turnover rate. Additionally, the EDG day tanks are skid mounted on the EDG skid and are enclosed within the diesel enclosure, which is maintained at a constant temperature during cold periods through operation of the EDG keepwarm system. Maintaining a constant temperature during cold periods minimizes EDG day tank thermal cycling and reduces the potential for condensation formation within the day tanks.

The project team reviewed the applicant's response and determined that the turnover rate for the day tanks is reasonable, and will prevent stratification of the fuel stored in the day tanks. Further, the enclosed location of the day tanks together with the use of the EDG keepwarm system to minimize thermal cycling of the tanks will reduce the potential for condensation forming inside the tanks. On this basis, the project team determined that the applicant's conclusion regarding day tank turnover rate is acceptable.

Upon further review of this exception, the project team noted that part of the justification is that the EDG day tanks are supplied by the EDG fuel storage tanks, which are routinely sampled and analyzed. The applicant was asked to provide additional information on the frequency of these activities.

In its response, the applicant stated that the following analyses are performed for the EDG fuel storage tank:

- Weekly – partial on-site lab fuel oil analysis, (API gravity, water and sediment, and kinematic viscosity)

- Weekly – complete off-site lab fuel oil analysis (particulate contamination, bacteria, API gravity, water and sediment, kinematic viscosity, sulfur content, flash point, cloud point, ash, distillation temperature, cetane index, carbon residue, and copper strip corrosion)
- After transfer from the main fuel oil tank – partial on-site lab fuel oil analysis, (API gravity, water and sediment, and kinematic viscosity)

- Monthly – oxidation stability

- Monthly – water and sediment (bottom sample)

The applicant further stated that fuel deliveries to the main fuel oil tank or directly to the EDG fuel storage tank are sampled as follows:

- On-site water and sediment and API gravity analysis before the tanker unloads

- Complete off-site lab fuel oil analysis (particulate contamination, bacteria, API gravity, water and sediment, kinematic viscosity, sulfur content, flash point, cloud point, ash, distillation temperature, cetane index, carbon residue, and copper strip corrosion)

The applicant further stated that all frequencies are less than that specified in NUREG-1801, AMP XI.M30, which stated in program element 5 that based on industry operating experience, quarterly sampling and analysis of fuel oil provides for timely detection of conditions conducive to corrosion.

The project team reviewed the applicant's response and determined that the sampling activities performed for the EDG fuel oil storage tank are in accordance with standard industry practices, and provide adequate monitoring of the EDG fuel oil to detect the presence of oil contamination. On this basis, the project team determined that the applicant's activities for sampling the EDG fuel oil storage tank are acceptable.

As part of the review for this exception, the project team reviewed the operating experience in the OCGS program basis document for AMP-B.1.22 (PBD-AMP-B.1.22) and noted that Oyster Creek experienced a problem with increasing levels of water and sediment in the bottom samples and the all-level samples from the EDG fuel oil storage tank in 2003. Based on this operating experience, the project team recognized that, since the EDG day tanks are filled by transferring oil from the EDG fuel oil storage tank, and the day tanks are not periodically sampled or inspected, water and sediment could have been inadvertently introduced into the day tanks during the transfer of oil from the EDG fuel oil storage tank without being detected. This leads to the possibility that undetected corrosion could be present in the day tanks. The applicant was asked to provide additional information on why the day tanks cannot be sampled, cleaned, or inspected, and what evidence exists to demonstrate that the aforementioned operating experience has not caused undetected corrosion in the day tanks.

In its response, the applicant stated that the day tanks are not equipped with sampling capability and periodic sampling will not be done for the day tanks; however, the OCGS fuel oil chemistry program, AMP B.1.22, will be revised to include a one-time inspection of the EDG day tanks.

In its letter dated April 17, 2006 (ML061150320), the applicant committed to revise OCGS AMP B.1.22, fuel oil chemistry, in the OCGS LRA to include a one-time internal inspection of the EDG day tanks to confirm the absence of aging effects. Visual inspection will be performed and further inspections will be performed to quantify the degradation, should there be any evidence of corrosion or pitting observed during the visual inspection. **This is Audit Commitment 3.0.3.2.19-1.**

The applicant further stated that the increasing trend in water and sediment in the EDG fuel oil storage tank was attributed to long-term accumulation. Prior to this 2003 event, Oyster Creek did not have in place recurring tasks to periodically drain accumulated water and sediment from the bottom of fuel oil storage tanks. Current Oyster Creek practice includes a quarterly recurring task to drain accumulated water and sediment from the bottom of the EDG fuel oil storage tank. The EDG fuel oil storage tank is also periodically drained, cleaned, and internally inspected every 10 years, and is periodically tested for water and sediment (bottom samples tested monthly; multilevel samples tested weekly and following transfer from the main fuel oil storage tank). Based on these current practices, which in part were developed as corrective actions to the 2003 event discussed above, and the fact that all sample results from that event were within specification, which is less than or equal to 0.05% water and sediment, current or impending problems in the EDG day tanks are not expected.

The project team reviewed the applicant's response and determined that the new commitment to perform a one-time inspection of the EDG day tanks will provide objective evidence to determine if undetected aging degradation is present. If indications of degradation are detected, further actions will be taken to quantify and, if necessary, correct the degradation. On this basis, the project team determined that the applicant's response is acceptable.

On the basis of its review of this exception, the applicant's responses to the audit questions, and the applicant's commitment to perform a one-time inspection of the EDG day tanks, the project team determined that this exception is acceptable, because a one-time inspection of the EDG day tanks will identify aging effects. If aging effects are detected, the applicant has committed to take appropriate actions.

<u>Exception 2</u>

Elements:
1. Scope of Program
3. Parameters Monitored or Inspected
4. Detection of Aging Effects
6. Acceptance Criteria

Exception: Oyster Creek has not committed to ASTM D 4057-95 (2000) for manual sampling standards:

Sampling of the Emergency Diesel Generator Fuel Storage Tank, although not directly comparable to any of the tank sampling methods described in ASTM D 4057-95 (2000), ensures that a multilevel sample and a bottom sample are obtained. The EDG Fuel Storage Tank is equipped with a sample station that includes a sample recirculation pump and sample collection points located internal to the tank at several tank elevations, thus making the Emergency Diesel Generator Fuel Storage Tank sample station effective for obtaining multilevel samples. Tank bottom samples are obtained through a sample line located ½" off of the bottom of the tank sump.

The GALL Report identifies the following recommendations for the ?scope of program," ?parameters monitored or inspected," ?detection of aging effects," and ?acceptance criteria" program elements associated with the exception taken:

1. *Scope of Program:* The program is focused on managing the conditions that cause general, pitting, and MIC of the diesel fuel tank internal surfaces in accordance with the plant's technical specifications (i.e., NUREG- 1430, NUREG-1431, NUREG-1432, NUREG-1433) on fuel oil purity and the guidelines of ASTM Standards D1796, D2276, D2709, D6217, and D4057. The program serves to reduce the potential of exposure of the tank internal surface to fuel oil contaminated with water and microbiological organisms.

3. *Parameters Monitored or Inspected:* The AMP monitors fuel oil quality and the levels of water and microbiological organisms in the fuel oil, which cause the loss of material of the tank internal surfaces. The ASTM Standard D 4057 is used for guidance on oil sampling. The ASTM Standards D 1796 and D 2709 are used for determination of water and sediment contamination in diesel fuel. For determination of particulates, modified ASTM D 2276, Method A, is used. The modification consists of using a filter with a pore size of 3.0 mm, instead of 0.8 mm. These are the principal parameters relevant to tank structural integrity.

4. *Detection of Aging Effects:* Degradation of the diesel fuel oil tank cannot occur without exposure of the tank internal surfaces to contaminants in the fuel oil, such as water and microbiological organisms. Compliance with diesel fuel oil standards in item 3, above, and periodic multilevel sampling provide assurance that fuel oil contaminants are below unacceptable levels. Internal surfaces of tanks that are drained for cleaning are visually inspected to detect potential degradation. However, corrosion may occur at locations in which contaminants may accumulate, such as a tank bottom, and an ultrasonic thickness measurement of the tank bottom surface ensures that significant degradation is not occurring.

6. *Acceptance Criteria:* The ASTM Standard D 4057 is used for guidance on oil sampling. The ASTM Standards D 1796 and D 2709 are used for guidance on the determination of water and sediment contamination in diesel fuel. ASTM D 6217 and Modified D 2276, Method A are used for guidance for determination of particulates. The modification to D 2276 consists of using a filter with a pore size of 3.0 mm, instead of 0.8 mm.

In reviewing this exception, the project team noted that neither the OCGS LRA nor the program basis document for this AMP discussed the specific sampling process used for the EDG fuel oil storage tank, or the differences compared to ASTM 4057-95. The applicant was asked to provide additional information on the sampling process used for the EDG fuel oil storage tank.

In its response, the applicant stated that sampling of the EDG fuel oil storage tank, although not directly comparable to any of the tank sampling methods described in ASTM D 4057-95 (2000), ensures that an ?all-levels" sample and a bottom sample are obtained. The EDG fuel oil storage tank is equipped with a sample station that includes a sample recirculation pump and sample collection points located internal to the tank at several tank elevations, thus making the

EDG fuel oil storage tank sample station effective for obtaining ?all-level" samples. Tank bottom samples are obtained through a sample line located off of the bottom of the tank sump which is specifically designed to collect the condensation/moisture and sediment from within the tank.

The applicant further stated that, from drawings CHO 082-1 and CHO 082-2, there are four 3/8" tubes that are used for sampling the tank. The bottom sample is taken from a tube that ends ½" from the bottom of the sump (about 5¼" below the tank bottom). The bottom sample is pulled by a pump that recirculates the oil back into the tank, discharging about 30" from the bottom of the tank. The tank sample is taken from a tube the ends ½" from the bottom of the tank. This sample is pulled by a pump and recirculated back into the tank, discharging about 30" from the tank bottom.

The project team reviewed the applicant's response and determined that additional information was needed to fully understand the EDG fuel oil storage tank sampling process, and how the sample station on the tank provided ?all-level" samples from the tank. The applicant was asked for additional information on the EDG fuel oil storage tank sampling process. In addition, information was requested on the main fuel oil storage tank sampling process, since it was not mentioned in the exception.

In its response, the applicant stated that the EDG fuel storage tank capacity is 1500 gallons. The recommendations in ASTM D 4057-95 (2000) for tap sampling are most analogous to the sampling techniques employed for the EDG fuel storage tank. The following compares the ASTM requirements for a 1500 gallon tank with the Oyster Creek sampling procedure:

- *Taps should be a minimum of ½" in diameter*: The Oyster Creek EDG sample tubes are 3/8", which is acceptable since the ASTM taps are gravity fed while Oyster Creek uses sample pumps to obtain samples.

- *Sample taps and piping should be flushed until they have been completely purged*: The Oyster Creek EDG sample pump is run for at least one minute to flush the sample lines and establish recirculation and mixing within the tank.

- *Sample tap specifications should meet the recommendations of ASTM D 4057-95 (2000) Tables 6 and 7*: The Oyster Creek sample taps do not meet the recommendations for number of taps and vertical location of the taps, as specified in ASTM D 4057-95 (2000). However, the sample pump provides for recirculation and mixing between elevation ½" and 30" within the EDG fuel storage tank. Although the tank sample inlet is located in the lower third of the tank, with recirculation and mixing, the sample is more representative of the tank contents than a bottom or lower third sample.

With regard to the sampling process for the main fuel oil storage tank, the applicant stated that the multilevel sampling of the main fuel oil tank meets the recommendations of the ASTM D 4057-95 (2000) guidance and, therefore, was not identified as an exception. The main fuel oil storage tank is 75,000 gallons and the ?running" or ?all-levels" sample method of ASTM D 4057-95 (2000) is used. Oyster Creek sampling procedure 828.7, ?Secondary Systems Analysis: Plant Oil" allows for the use of either a metal sampling cage or a weighted sampling bottle, as described in ASTM D 4057-95 (2000). A clean, dried, and corked sampler is lowered from the top of the tank through a manhole to approximately one foot above the tank bottom. The cork is removed and the sampler is raised at a uniform rate. If the sample volume is not between 50% and 85%, it is discarded and another sample is obtained. Once an acceptable sample is obtained, it is emptied into a sample bottle, if required, and capped.

The project team reviewed the applicant's response, as well as ASTM D 4057-95 (2000) and the applicants oil sampling procedure 828.7. The Oyster Creek technical staff were also interviewed to discuss the sample station operation. The project team determined that, while there are four sample tubes in the EDG fuel oil storage tank sample station, two are used to supply suction to the recirculation pumps, and two are used as return lines from the recirculation pumps back to the tank. Therefore, there are effectively only two locations within the tank from which oil samples are taken; one is from the tank sump and one is ½" from the tank bottom. True ?multilevel" sampling is not obtained for the EDG fuel oil storage tank. The sample station used by Oyster Creek provides for a simulated multilevel sample through the use of recirculation and mixing of the oil. For the tank sample, oil is pumped from the tube located ½" from the tank bottom and recirculated back to the tank through the tube discharging 30" from the tank bottom. This recirculation continues for at least one minute before a sample is taken, which allows mixing to occur between the ½" and 30" elevations. Since the tank sample is obtained from the lower third of the tank, and the use of recirculation pumps will provide some degree of mixing with fuel oil from the middle level of the tank, the Oyster Creek sampling procedure will provide a conservative estimate of contaminants in the fuel oil, which tend to settle to the lower levels of the tank. On this basis, the project team determined that this exception is acceptable.

Exception 3

Elements:

1. Scope of Program
3. Parameters Monitored or Inspected
4. Detection of Aging Effects
6. Acceptance Criteria

Exception:

Oyster Creek has not committed to ASTM D 4057-95 (2000) for manual sampling standards:

Fire Pond Diesel Fuel Tank samples are obtained from the tank fuel oil outlet line located 4" off of the bottom of the tanks. The Fire Pond Diesel Fuel Tanks are each 2.1 cu meter (550 gallons) capacity. Spot sampling recommendations in ASTM D 4057-95 (2000) for tanks less than or equal to 159 cu meter include a single sample from the middle (a distance of one-half of the depth of liquid below the liquid's surface). Although the actual sample location is lower in the tank than prescribed by the ASTM, the lower elevation is more likely to contain contaminants and water and sediment which tend to settle in the tank, thus making this an effective spot sampling location. Bottom samples from the Fire Pond Diesel Fuel Tanks are taken off of the tank drain located on the bottom of the tank.

The GALL Report identifies the following recommendations for the ?scope of program," ?parameters monitored or inspected," ?detection of aging effects," and ?acceptance criteria" program elements associated with the exception taken:

1. *Scope of Program:* The program is focused on managing the conditions that cause general, pitting, and MIC of the diesel fuel tank internal surfaces in accordance with the plant's technical specifications (i.e., NUREG- 1430, NUREG-1431, NUREG-1432, NUREG-1433) on fuel oil purity and the guidelines of ASTM Standards D1796, D2276, D2709, D6217, and D4057. The program serves to reduce the potential of exposure of the tank internal surface to fuel oil contaminated with water and microbiological organisms.

3. *Parameters Monitored or Inspected:* The AMP monitors fuel oil quality and the levels of water and microbiological organisms in the fuel oil, which cause the loss of material of the tank internal surfaces. The ASTM Standard D 4057 is used for guidance on oil sampling. The ASTM Standards D 1796 and D 2709 are used for determination of water and sediment contamination in diesel fuel. For determination of particulates, modified ASTM D 2276, Method A, is used. The modification consists of using a filter with a pore size of 3.0 mm, instead of 0.8 mm. These are the principal parameters relevant to tank structural integrity.

4. *Detection of Aging Effects:* Degradation of the diesel fuel oil tank cannot occur without exposure of the tank internal surfaces to contaminants in the fuel oil, such as water and microbiological organisms. Compliance with diesel fuel oil standards in item 3, above, and periodic multilevel sampling provide assurance that fuel oil contaminants are below unacceptable levels. Internal surfaces of tanks that are drained for cleaning are visually inspected to detect potential degradation. However, corrosion may occur at locations in which contaminants may accumulate, such as a tank bottom, and an ultrasonic thickness measurement of the tank bottom surface ensures that significant degradation is not occurring.

6. *Acceptance Criteria:* The ASTM Standard D 4057 is used for guidance on oil sampling. The ASTM Standards D 1796 and D 2709 are used for guidance on the determination of water and sediment contamination in diesel fuel. ASTM D 6217 and Modified D 2276, Method A, are used for guidance for determination of particulates. The modification to D 2276 consists of using a filter with a pore size of 3.0 mm, instead of 0.8 mm.

In reviewing this exception, the project team reviewed ASTM D 4057-95 (2000). For fuel oil storage tanks less than 159 cubic meters, spot sampling recommendations in ASTM D 4057-95 (2000) include a single sample from the middle (a distance of one-half of the depth of liquid below the liquid's surface). Since the OCGS fire pond diesel fuel oil storage tanks are 2.1 cubic meters, the spot sampling requirements in ASTM D 4057 are applicable. The project team recognized that the actual sample location for the OCGS fire pond diesel fuel oil storage tanks is lower in the tanks than prescribed by the ASTM D 4057 standard, which will result in the samples being more likely to capture contaminants, water and sediment. Therefore, the samples are expected to be conservatively representative of the fuel in the tank. On this basis, the project team determined that this exception is acceptable.

Exception 4

Elements: 1. Scope of Program
2. Preventive Actions

Exception: Oyster Creek does not add corrosion inhibitors to fuel oil. The analysis for particulate contaminants using modified ASTM D 2276-00 Method A is sufficient for the detection of corrosion products at an early stage. Fuel contaminants and degradation products will normally settle to the tank bottom where they would be detected by routine analysis or by periodic draining of water and sediment from the storage tank bottoms.

The GALL Report identifies the following recommendations for the ?scope of program" and ?preventive actions" program elements associated with the exception taken:

1. *Scope of Program:* The program is focused on managing the conditions that cause general, pitting, and MIC of the diesel fuel tank internal surfaces in accordance with the plant's technical specifications (i.e., NUREG- 1430, NUREG-1431, NUREG-1432, NUREG-1433) on fuel oil purity and the guidelines of ASTM Standards D1796, D2276, D2709, D6217, and D4057. The program serves to reduce the potential of exposure of the tank internal surface to fuel oil contaminated with water and microbiological organisms.

2. *Preventive Actions:* The quality of fuel oil is maintained by additions of biocides to minimize biological activity, stabilizers to prevent biological breakdown of the diesel fuel, and corrosion inhibitors to mitigate corrosion. Periodic cleaning of a tank allows removal of sediments, and periodic draining of water collected at the bottom of a tank minimizes the amount of water and the length of contact time. Accordingly, these measures are effective in mitigating corrosion inside diesel fuel oil tanks. Coatings, if used, prevent or mitigate corrosion by protecting the internal surfaces of the tank from contact with water and microbiological organisms.

In evaluating this exception, the project team reviewed the applicant's fuel oil sampling activities to determine if they are adequate to provide timely detection of corrosion. From the applicant's response to an audit question, the project team determined that fuel oil analyses for particulates, as well as water and sediment, are performed quarterly or more frequently for the Oyster Creek fuel oil storage tanks. In particular, in its response to an audit question, the applicant stated that complete off-site lab fuel oil analyses are performed for particulate contamination, bacteria, API gravity, water and sediment, kinematic viscosity, sulfur content, flash point, cloud point, ash, distillation temperature, cetane index, carbon residue, and copper strip corrosion. This is performed weekly for the EDG fuel oil storage tank, and quarterly for the main fuel oil storage tank. In addition, the main fuel oil storage tank, the EDG fuel oil storage tank, and the fire pond diesel fuel tanks will be periodically drained, cleaned and inspected. A one-time inspection will be performed for the EDG day tanks. The project team determined that the applicant's fuel oil sampling activities, together with the inspection activities will provide assurance that, if corrosion were occurring in the fuel oil tanks, it would be detected in a timely manner. If evidence of corrosion is detected, corrective actions will be taken to mitigate it. On this basis, the project team determined that this exception is acceptable.

In Attachment 1, Item B.1.22 of its reconciliation document, the applicant identified the following additional exception to the GALL Report program, which is not included in the OCGS LRA:

<u>Exception 5</u>

Element: 1. Scope of Program

Exception: NUREG-1801 states in XI.M30 that the fuel oil aging management program is in part based on the fuel oil purity and testing requirements of the plant's Technical Specifications that are based on the Standard Technical Specifications of NUREG-1430 through NUREG-1433. Oyster Creek has not adopted the Standard Technical Specifications as described in these NUREGs, however, the Oyster Creek fuel oil specifications and procedures invoke similar requirements for fuel oil purity and fuel oil testing, as described by the Standard Technical Specifications. These include testing requirements for new fuel oil (API gravity, kinematic viscosity, water and sediment) prior to adding the new fuel to the storage tank to ensure that the oil has not been contaminated with substances that would have an immediate detrimental impact on diesel engine combustion, and testing of new fuel after adding it to the storage tank to confirm that the remaining fuel oil properties are within specification requirements. Oyster Creek fuel oil activities also provide for the trending of particulate contamination in new and stored fuel oil. Water and Sediment are drained periodically (quarterly) from the Emergency Diesel Generator Fuel Storage Tank. This periodicity exceeds the Standard Technical Specifications requirements of "once every [31] days", however, it is aligned with the requirements of Regulatory Guide 1.137, which states that a quarterly basis is sufficient unless accumulated condensation is suspected (in which case a monthly basis is appropriate). *This is a new exception based on the reconciliation of this aging management program from the draft January 2005 GALL to the approved September 2005 GALL.*

The GALL Report identifies the following recommendations for the ?scope of program” program element associated with the exception taken:

1. *Scope of Program:* The program is focused on managing the conditions that cause general, pitting, and MIC of the diesel fuel tank internal surfaces in accordance with the plant’s technical specifications (i.e., NUREG- 1430, NUREG-1431, NUREG-1432, NUREG-1433) on fuel oil purity and the guidelines of ASTM Standards D1796, D2276, D2709, D6217, and D4057. The program serves to reduce the potential of exposure of the tank internal surface to fuel oil contaminated with water and microbiological organisms.

The applicant was asked to confirm that AMP B.1.22 in the OCGS LRA will be revised to include this exception.

In its letter dated March 30, 2006 (ML060950408), the applicant committed to revise AMP B.1.22 in the OCGS LRA to include the exception identified in the reconciliation document, which stated that Oyster Creek has not adopted the Standard Technical Specifications, however, the Oyster Creek fuel oil specifications and procedures invoke similar requirements for fuel oil purity and fuel oil testing. **This is Audit Commitment 3.0.3.2.19-2.**

The applicant was asked to provide additional information on the specific fuel oil specifications used at Oyster Creek, and how they differ from the requirements in the standard technical specifications. The applicant was also asked to justify the frequency for draining water and sediment from the EDG fuel storage tank in light of past operating experience at Oyster Creek, in which increasing water and sediment concentrations were observed in the stored fuel oil.

In its response, the applicant stated that water and sediment are drained from the EDG fuel storage tank on a quarterly basis. This exceeds the standard technical specifications requirements of 31 days; however, it is aligned with Regulatory Guide 1.137. Regulatory Guide 1.137 states that a quarterly basis is sufficient unless accumulated condensation is suspected, in which case a monthly basis is appropriate. With regard to the frequency for draining water and sediment from the EDG fuel oil storage tank, the applicant stated that the increasing trend in water and sediment was attributed to long-term accumulation. Prior to this event, Oyster Creek did not have in place recurring tasks to periodically drain water and sediment from the bottom of fuel oil storage tanks. Current Oyster Creek practices include quarterly recurring tasks to drain accumulated water and sediment from the bottom of the EDG fuel oil storage tank. This practice has been effective in preventing recurrence of high levels of water and sediment in the EDG fuel oil storage tank.

The applicant further stated in its response that the standard technical specifications reference Regulatory Guide 1.137 for recommended fuel oil practices, as supplemented by ANSI N195. The fuel oil properties governed by these requirements are the water and sediment content, the kinematic viscosity, specific or API gravity, and impurity level. These fuel oil properties are governed by the Oyster Creek fuel oil chemistry program, which is implemented by procurement specification SP-1302-38-010 and sampling and analysis procedure CY-OC-120-1107. These procedures are based on Regulatory Guide 1.137, Revision 1, ANSI N195-1976 and ASTM D975-81. These implementing documents include fuel oil requirements for water and sediment content, the kinematic viscosity, specific or API gravity, and impurity level for new and stored fuel consistent with the requirements identified in the referenced standard technical specifications.

The project team reviewed the applicant's response, as well as OCGS procurement specification SP-1302-38-010, ?Oyster Creek Generating Station Diesel Fuel Oil No. 2," Revision 8, June 23, 2004; Oyster Creek sampling and analysis procedure CY-OC-120-1107, ?Fuel Oil Sample and Analysis Schedule," Revision 0; and the standard technical specifications for General Electric plants, NUREG-1433, ?Standard Technical Specifications General Electric Plants, BWR/4," Volume 1, Revision 3, June 2004. The project team confirmed that the implementing documents included fuel oil requirements for water and sediment content, the kinematic viscosity, specific or API gravity, and impurity level for new and stored fuel consistent with the requirements identified in the referenced standard technical specifications; therefore, the applicant's fuel oil specifications are consistent with the requirements in the standard technical specifications. On this basis, the project team determined that this exception is acceptable.

3.0.3.2.19.4 Enhancements

In the OCGS LRA, the applicant identified the following enhancements in order to meet the GALL Report program elements:

Enhancement 1

Elements: 1. Scope of Program
3. Parameters Monitored or Inspected

4. Detection of Aging Effects
5. Monitoring and Trending
6. Acceptance Criteria

Enhancement: The Oyster Creek Fuel Oil Chemistry program will be enhanced to include routine analysis for particulate contamination using modified ASTM D 2276-00 Method A on fuel oil samples from the Emergency Diesel Generator Fuel Storage Tank, the Fire Pond Diesel Fuel Tanks, and the Main Fuel Oil Tank.

The GALL Report identifies the following recommendations for the ?scope of program," ?parameters monitored or inspected," ?detection of aging effects," ?monitoring and trending," and ?acceptance criteria" program elements associated with the stated enhancement:

1. *Scope of Program:* The program is focused on managing the conditions that cause general, pitting, and MIC of the diesel fuel tank internal surfaces in accordance with the plant's technical specifications (i.e., NUREG- 1430, NUREG-1431, NUREG-1432, NUREG-1433) on fuel oil purity and the guidelines of ASTM Standards D1796, D2276, D2709, D6217, and D4057. The program serves to reduce the potential of exposure of the tank internal surface to fuel oil contaminated with water and microbiological organisms.

3. *Parameters Monitored or Inspected:* The AMP monitors fuel oil quality and the levels of water and microbiological organisms in the fuel oil, which cause the loss of material of the tank internal surfaces. The ASTM Standard D 4057 is used for guidance on oil sampling. The ASTM Standards D 1796 and D 2709 are used for determination of water and sediment contamination in diesel fuel. For determination of particulates, modified ASTM D 2276, Method A, is used. The modification consists of using a filter with a pore size of 3.0 mm, instead of 0.8 mm. These are the principal parameters relevant to tank structural integrity.

4. *Detection of Aging Effects:* Degradation of the diesel fuel oil tank cannot occur without exposure of the tank internal surfaces to contaminants in the fuel oil, such as water and microbiological organisms. Compliance with diesel fuel oil standards in item 3, above, and periodic multilevel sampling provide assurance that fuel oil contaminants are below unacceptable levels. Internal surfaces of tanks that are drained for cleaning are visually inspected to detect potential degradation. However, corrosion may occur at locations in which contaminants may accumulate, such as a tank bottom, and an ultrasonic thickness measurement of the tank bottom surface ensures that significant degradation is not occurring.

5. *Monitoring and Trending:* Water and biological activity or particulate contamination concentrations are monitored and trended in accordance with the plant's technical specifications or at least quarterly. Based on industry operating experience, quarterly sampling and analysis of fuel oil provides for timely detection of conditions conducive to corrosion of the internal surface of the diesel fuel oil tank before the potential loss of its intended function.

6. *Acceptance Criteria:* The ASTM Standard D 4057 is used for guidance on oil sampling. The ASTM Standards D 1796 and D 2709 are used for guidance on the determination of water and sediment contamination in diesel fuel. ASTM D 6217 and

Modified D 2276, Method A are used for guidance for determination of particulates. The modification to D 2276 consists of using a filter with a pore size of 3.0 mm, instead of 0.8 mm.

The applicant's enhancement will add routine analysis for particulate contamination using modified ASTM D 2276-00 Method A on fuel oil samples from the EDG fuel storage tank, the fire pond diesel fuel tanks, and the main fuel oil tank, which is consistent with the recommendations in the GALL Report. Routine analysis for particulate contamination will provide results that can be used to ensure that contamination is maintained at acceptable levels.

On this basis, the project team found this enhancement acceptable since when the enhancement is implemented, OCGS AMP B.1.22, ?Fuel Oil Chemistry," will be consistent with GALL AMP XI.M30 and will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 2

Elements:	1. Scope of Program 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring and Trending 6. Acceptance Criteria
Enhancement:	The Oyster Creek Fuel Oil Chemistry program will be enhanced to include analysis for particulate contamination using modified ASTM D 2276-00 Method A on new fuel oil.

The GALL Report identifies the following recommendations for the ?scope of program," ?parameters monitored or inspected," ?detection of aging effects," ?monitoring and trending," and ?acceptance criteria" program elements associated with the stated enhancement:

1. *Scope of Program:* The program is focused on managing the conditions that cause general, pitting, and MIC of the diesel fuel tank internal surfaces in accordance with the plant's technical specifications (i.e., NUREG- 1430, NUREG-1431, NUREG-1432, NUREG-1433) on fuel oil purity and the guidelines of ASTM Standards D1796, D2276, D2709, D6217, and D4057. The program serves to reduce the potential of exposure of the tank internal surface to fuel oil contaminated with water and microbiological organisms.

3. *Parameters Monitored or Inspected:* The AMP monitors fuel oil quality and the levels of water and microbiological organisms in the fuel oil, which cause the loss of material of the tank internal surfaces. The ASTM Standard D 4057 is used for guidance on oil sampling. The ASTM Standards D 1796 and D 2709 are used for determination of water and sediment contamination in diesel fuel. For determination of particulates, modified ASTM D 2276, Method A, is used. The modification consists of using a filter with a pore size of 3.0 mm, instead of 0.8 mm. These are the principal parameters relevant to tank structural integrity.

4. *Detection of Aging Effects:* Degradation of the diesel fuel oil tank cannot occur without exposure of the tank internal surfaces to contaminants in the fuel oil, such as water and

microbiological organisms. Compliance with diesel fuel oil standards in item 3, above, and periodic multilevel sampling provide assurance that fuel oil contaminants are below unacceptable levels. Internal surfaces of tanks that are drained for cleaning are visually inspected to detect potential degradation. However, corrosion may occur at locations in which contaminants may accumulate, such as a tank bottom, and an ultrasonic thickness measurement of the tank bottom surface ensures that significant degradation is not occurring.

5. *Monitoring and Trending:* Water and biological activity or particulate contamination concentrations are monitored and trended in accordance with the plant's technical specifications or at least quarterly. Based on industry operating experience, quarterly sampling and analysis of fuel oil provides for timely detection of conditions conducive to corrosion of the internal surface of the diesel fuel oil tank before the potential loss of its intended function.

6. *Acceptance Criteria:* The ASTM Standard D 4057 is used for guidance on oil sampling. The ASTM Standards D 1796 and D 2709 are used for guidance on the determination of water and sediment contamination in diesel fuel. ASTM D 6217 and Modified D 2276, Method A are used for guidance for determination of particulates. The modification to D 2276 consists of using a filter with a pore size of 3.0 mm, instead of 0.8 mm.

The applicant's enhancement will add routine analysis for particulate contamination using modified ASTM D 2276-00 Method A on new fuel oil, which is consistent with the recommendations in the GALL Report. Routine analysis for particulate contamination will provide results that can be used to ensure that contamination from new fuel oil is not introduced into the OCGS fuel oil system.

On this basis, the project team found this enhancement acceptable since when the enhancement is implemented, OCGS AMP B.1.22, ?Fuel Oil Chemistry," will be consistent with GALL AMP XI.M30 and will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 3

Elements:	1. Scope of Program 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring and Trending 6. Acceptance Criteria
Enhancement:	The Oyster Creek Fuel Oil Chemistry program will be enhanced to include analysis for water and sediment using ASTM D 2709-96 for Fire Pond Diesel Fuel Tank bottom samples.

The GALL Report identifies the following recommendations for the ?scope of program," ?parameters monitored or inspected," ?detection of aging effects," ?monitoring and trending," and ?acceptance criteria" program elements associated with the stated enhancement:

1. *Scope of Program:* The program is focused on managing the conditions that cause general, pitting, and MIC of the diesel fuel tank internal surfaces in accordance with the

plant's technical specifications (i.e., NUREG- 1430, NUREG-1431, NUREG-1432, NUREG-1433) on fuel oil purity and the guidelines of ASTM Standards D1796, D2276, D2709, D6217, and D4057. The program serves to reduce the potential of exposure of the tank internal surface to fuel oil contaminated with water and microbiological organisms.

3. *Parameters Monitored or Inspected:* The AMP monitors fuel oil quality and the levels of water and microbiological organisms in the fuel oil, which cause the loss of material of the tank internal surfaces. The ASTM Standard D 4057 is used for guidance on oil sampling. The ASTM Standards D 1796 and D 2709 are used for determination of water and sediment contamination in diesel fuel. For determination of particulates, modified ASTM D 2276, Method A, is used. The modification consists of using a filter with a pore size of 3.0 mm, instead of 0.8 mm. These are the principal parameters relevant to tank structural integrity.

4. *Detection of Aging Effects:* Degradation of the diesel fuel oil tank cannot occur without exposure of the tank internal surfaces to contaminants in the fuel oil, such as water and microbiological organisms. Compliance with diesel fuel oil standards in item 3, above, and periodic multilevel sampling provide assurance that fuel oil contaminants are below unacceptable levels. Internal surfaces of tanks that are drained for cleaning are visually inspected to detect potential degradation. However, corrosion may occur at locations in which contaminants may accumulate, such as a tank bottom, and an ultrasonic thickness measurement of the tank bottom surface ensures that significant degradation is not occurring.

5. *Monitoring and Trending:* Water and biological activity or particulate contamination concentrations are monitored and trended in accordance with the plant's technical specifications or at least quarterly. Based on industry operating experience, quarterly sampling and analysis of fuel oil provides for timely detection of conditions conducive to corrosion of the internal surface of the diesel fuel oil tank before the potential loss of its intended function.

6. *Acceptance Criteria:* The ASTM Standard D 4057 is used for guidance on oil sampling. The ASTM Standards D 1796 and D 2709 are used for guidance on the determination of water and sediment contamination in diesel fuel. ASTM D 6217 and Modified D 2276, Method A are used for guidance for determination of particulates. The modification to D 2276 consists of using a filter with a pore size of 3.0 mm, instead of 0.8 mm.

The applicant's enhancement will add routine analysis for water and sediment using ASTM D 2709-96 for fire pond diesel fuel tank bottom samples, which is consistent with the recommendations in the GALL Report. Routine analysis for water and sediment in the fire pond diesel fuel tank will provide results that can be used to ensure that these contaminants are maintained at acceptable levels, and that the frequency for draining water and sediment from the tanks is adequate.

On this basis, the project team found this enhancement acceptable since when the enhancement is implemented, OCGS AMP B.1.22, ?Fuel Oil Chemistry," will be consistent with GALL AMP XI.M30 and will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 4

Elements:	1. Scope of Program 2. Preventive Actions 4. Detection of Aging Effects
Enhancement:	The Oyster Creek Fuel Oil Chemistry program will be enhanced to include analysis for bacteria to verify the effectiveness of biocide addition in the Emergency Diesel Generator Fuel Storage Tank, the Fire Pond Diesel Fuel Tanks, and the Main Fuel Oil Tank.

The GALL Report identifies the following recommendations for the ?scope of program," ?preventive actions," and ?detection of aging effects" program elements associated with the stated enhancement:

1. *Scope of Program:* The program is focused on managing the conditions that cause general, pitting, and MIC (MIC) of the diesel fuel tank internal surfaces in accordance with the plant's technical specifications (i.e., NUREG- 1430, NUREG-1431, NUREG-1432, NUREG-1433) on fuel oil purity and the guidelines of ASTM Standards D1796, D2276, D2709, D6217, and D4057. The program serves to reduce the potential of exposure of the tank internal surface to fuel oil contaminated with water and microbiological organisms.

2. *Preventive Actions:* The quality of fuel oil is maintained by additions of biocides to minimize biological activity, stabilizers to prevent biological breakdown of the diesel fuel, and corrosion inhibitors to mitigate corrosion. Periodic cleaning of a tank allows removal of sediments, and periodic draining of water collected at the bottom of a tank minimizes the amount of water and the length of contact time. Accordingly, these measures are effective in mitigating corrosion inside diesel fuel oil tanks. Coatings, if used, prevent or mitigate corrosion by protecting the internal surfaces of the tank from contact with water and microbiological organisms.

4. *Detection of Aging Effects:* Degradation of the diesel fuel oil tank cannot occur without exposure of the tank internal surfaces to contaminants in the fuel oil, such as water and microbiological organisms. Compliance with diesel fuel oil standards in item 3, above, and periodic multilevel sampling provide assurance that fuel oil contaminants are below unacceptable levels. Internal surfaces of tanks that are drained for cleaning are visually inspected to detect potential degradation. However, corrosion may occur at locations in which contaminants may accumulate, such as a tank bottom, and an ultrasonic thickness measurement of the tank bottom surface ensures that significant degradation is not occurring.

The applicant's enhancement will add routine analysis for bacteria to verify the effectiveness of biocide addition in the EDG fuel storage tank, the fire pond diesel fuel tanks, and the main fuel oil tank, which is consistent with the recommendations in the GALL Report. Routine analysis for bacteria will provide results that can be used to ensure that the biocide addition activities are effective in preventing the growth of bacteria in the fuel oil system.

On this basis, the project team found this enhancement acceptable since when the enhancement is implemented, OCGS AMP B.1.22, :Fuel Oil Chemistry," will be consistent with

GALL AMP XI.M30 and will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 5

Elements:	1. Scope of Program 2. Preventive Actions 4. Detection of Aging Effects
Enhancement:	The Oyster Creek Fuel Oil Chemistry program will be enhanced to include periodic draining, cleaning, and inspection of the Fire Pond Diesel Fuel Tanks and the Main Fuel Oil Tank (already performed for the Emergency Diesel Generator Fuel Storage Tank). Inspection activities will include the use of ultrasonic techniques for determining tank bottom thicknesses should there be any evidence of corrosion or pitting.

The GALL Report identifies the following recommendations for the ?scope of program," ?preventive actions," and ?detection of aging effects" program elements associated with the stated enhancement:

1. *Scope of Program:* The program is focused on managing the conditions that cause general, pitting, and MIC of the diesel fuel tank internal surfaces in accordance with the plant's technical specifications (i.e., NUREG- 1430, NUREG-1431, NUREG-1432, NUREG-1433) on fuel oil purity and the guidelines of ASTM Standards D1796, D2276, D2709, D6217, and D4057. The program serves to reduce the potential of exposure of the tank internal surface to fuel oil contaminated with water and microbiological organisms.

2. *Preventive Actions:* The quality of fuel oil is maintained by additions of biocides to minimize biological activity, stabilizers to prevent biological breakdown of the diesel fuel, and corrosion inhibitors to mitigate corrosion. Periodic cleaning of a tank allows removal of sediments, and periodic draining of water collected at the bottom of a tank minimizes the amount of water and the length of contact time. Accordingly, these measures are effective in mitigating corrosion inside diesel fuel oil tanks. Coatings, if used, prevent or mitigate corrosion by protecting the internal surfaces of the tank from contact with water and microbiological organisms.

4. *Detection of Aging Effects:* Degradation of the diesel fuel oil tank cannot occur without exposure of the tank internal surfaces to contaminants in the fuel oil, such as water and microbiological organisms. Compliance with diesel fuel oil standards in item 3, above, and periodic multilevel sampling provide assurance that fuel oil contaminants are below unacceptable levels. Internal surfaces of tanks that are drained for cleaning are visually inspected to detect potential degradation. However, corrosion may occur at locations in which contaminants may accumulate, such as a tank bottom, and an ultrasonic thickness measurement of the tank bottom surface ensures that significant degradation is not occurring.

The applicant's enhancement will add periodic draining, cleaning, and inspection of the fire pond diesel fuel tanks and the main fuel oil tank. This activity is already performed for the emergency diesel generator fuel storage tank. Inspection activities will include the use of ultrasonic techniques for determining tank bottom thicknesses, should there be any evidence of corrosion or pitting. This activity is consistent with the recommendations in the GALL Report, and will ensure that aging of the fire pond diesel fuel tanks and the main fuel oil tank is properly managed.

On this basis, the project team found this enhancement acceptable since when the enhancement is implemented, OCGS AMP B.1.22, ?Fuel Oil Chemistry," will be consistent with GALL AMP XI.M30 and will provide additional assurance that the effects of aging will be adequately managed.

3.0.3.2.19.5 Operating Experience

In the OCGS LRA, the applicant stated that the fuel oil chemistry aging management program has proven to be effective in identifying and correcting abnormal conditions in a timely manner. In 2003, Oyster Creek experienced high concentrations of water and sediment in main fuel oil tank samples. On previous occasions, high concentrations of water and sediment had also been detected in the EDG fuel storage tank and fire pond diesel fuel tanks. There were no fuel oil system failures attributed to a loss of material condition or biofouling as a result of these findings. Although fuel oil chemistry activities detected the high levels of contaminants in the fuel in a timely manner, and corrective actions were initiated before blockage of fuel oil system supply lines or corrosion of fuel oil tanks and fuel supply lines occurred, fuel oil chemistry activities were enhanced to include the addition of biocides and stabilizers to fuel oil, and to incorporate improved test methods for the early detection of water and sediment.

In reviewing the applicant's operating experience, the project team noted that the discussion of operating experience in the program basis document for AMP B.1.22, PBD-AMP-B.1.22, stated that Oyster Creek experienced an increasing trend in the concentration of water and sediment in EDG fuel oil storage tank bottom and multilevel samples. Corrective actions involved using a feed and bleed process to replace the oil in the EDG fuel oil storage tank. The project team asked the applicant to provide additional information on the root cause and severity of this problem, along with how the problem was corrected.

In its response, the applicant stated that the events involving increasing trends in water and sediment in the EDG fuel storage tank bottom and multilevel samples were attributed to long-term accumulation. Prior to this event, Oyster Creek did not have in place recurring tasks to periodically drain water and sediment from the bottom of fuel oil storage tanks. Current Oyster Creek practices include quarterly periodic recurring tasks to drain accumulated water and sediment from the bottoms of the EDG fuel storage tank, fire pond diesel fuel tanks, and the main fuel oil tank.

The applicant further stated in its response that an increase was noted in the monthly EDG storage tank bottoms sample from 10/08/03 as water and sediment increased from < 0.05% to 0.05%. A weekly EDG storage tank sample from 10/05/03 also indicated an increase from < 0.05% to 0.05%. All sample results from the EDG storage tank and bottoms were within the specification, which is less than or equal to 0.05% water and sediment. On 10/09/03, the plant obtained the use of a vacuum truck and a tanker truck. The vacuum truck pulled aproximately 400 gallons of EDG fuel oil off the tank's sump. The tanker truck then made up to the tank by adding 400 gallons of clean fuel oil. This process was repeated an additional four times so that approximately 1870 gallons of oil was bled from the tank and 1870 gallons of fresh oil was added to the tank. A subsequent bulk sample was taken on 10/10/03 and was < 0.05% water and sediment. The increased trend in water and sediment was attributed to long-term accumulation. The use of the feed and bleed process to replace the fuel oil in the EDG fuel storage tank was not intended to address the root cause of this increasing trend. Actions to prevent recurrence included the creation of quarterly recurring tasks to drain accumulated water and sediment from the bottoms of the EDG fuel storage tank, the fire pond diesel fuel tanks, and the main fuel oil tank.

The project team reviewed the applicants response and determined that the increasing trend in water and sediment in the fuel oil storage tanks was a result of long-term accumulation since Oyster Creek did not periodically drain water and sediment from the tanks. Water tends to accumulate in fuel oil tanks due to condensation inside the tanks if they are subjected to thermal cycling, which is typical of outdoor tanks. Subsequent to this event, Oyster Creek implemented recurring tasks to periodically drain water and sediment from the tanks, which eliminated the problem. On this basis, the project team determined that the applicant's corrective actions to address the increasing water content of the fuel oil were acceptable, and periodic monitoring of the fuel oil tanks will detect any recurrence of this problem.

The project team reviewed the operating experience provided in the OCGS LRA, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience, and discussions with the applicant's technical staff, the project team determined that the applicant's fuel oil chemistry program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.2.19.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the fuel oil chemistry program in OCGS LRA, Appendix A, Section A.1.22, which stated that the fuel oil chemistry aging management program is an existing program that includes preventive activities to provide assurance that contaminants are maintained at acceptable levels in fuel oil for systems and components within the scope of license renewal. The fuel oil tanks within the scope of license renewal are maintained by monitoring and controlling fuel oil contaminants in accordance with the guidelines of the American Society for Testing and Materials (ASTM). Fuel oil sampling and analysis is performed in accordance with approved procedures for new fuel and stored fuel. Fuel oil tanks are periodically drained of accumulated water and sediment. These activities effectively manage the effects of aging by providing reasonable assurance that potentially harmful contaminants are maintained at low concentrations. The fuel oil chemistry aging management program will be enhanced to include:

- Routine analysis for particulate contamination using modified ASTM D 2276-00 Method A on fuel oil samples from the emergency diesel generator fuel storage tank, the fire pond diesel fuel tanks, and the main fuel oil tank.

- Analysis for particulate contamination using modified ASTM D 2276-00 Method A on new fuel oil.

- Analysis for water and sediment using ASTM D 2709-96 for fire pond diesel fuel tank bottom samples

- Analysis for bacteria to verify the effectiveness of biocide addition in the emergency diesel generator fuel storage tank, the fire pond diesel fuel tanks, and the main fuel oil tank.

- Periodic draining, cleaning, and inspection of the fire pond diesel fuel tanks and the main fuel oil tank. Inspection activities will include the use of ultrasonic techniques for determining tank bottom thicknesses should there be any evidence of corrosion or pitting.

These enhancements will be implemented prior to the period of extended operation.

The project team also reviewed the applicant's license renewal commitment list in Appendix A of the OCGS LRA, and confirmed that the enhancements to this program are identified and will be implemented prior to the period of extended operation as item 22 of the commitments.

In its letter dated April 17, 2006 (ML061150320), the applicant committed to the following:

- AMP B.1.22, fuel oil chemistry, in the OCGS LRA will be revised to include a one-time internal inspection of the EDG day tanks to confirm the absence of aging effects. Visual inspection will be performed and further inspections will be performed to quantify the degradation, should there be any evidence of corrosion or pitting observed during the visual inspection. (commitment 3.0.3.2.19-1).

In its letter dated March 30, 2006 (ML060950408), the applicant committed to the following:

- AMP B.1.22, fuel oil chemistry, in the OCGS LRA will be revised to include the exception identified in Attachment 1, item B.1.22 of the reconciliation document, which stated that Oyster Creek has not adopted the Standard Technical Specifications, however, the Oyster Creek fuel oil specifications and procedures invoke similar requirements for fuel oil purity and fuel oil testing. (commitment 3.0.3.2.19-2).

The applicant's license renewal commitment list and UFSAR update are to be revised to reflect these Audit Commitments.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.22. Contingent upon the addition of audit commitments 3.0.3.2.19-1 and 3.0.3.2.19-2, the project team found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.2.19.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report are consistent with the GALL Report. In addition, the project team reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. Also, the project team reviewed the enhancements and determined that implementation of the enhancements prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The project team also reviewed the UFSAR Supplement for this AMP and, contingent upon the inclusion of audit commitment 3.0.3.2.19-1 and 3.0.3.2.19-2, found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.20 Reactor Vessel Surveillance (OCGS AMP B.1.23)

This AMP is assigned to the Office of Nuclear Reactor Regulation, Division of Engineering staff and will be addressed separately in Section 3.0.3.3 of the SER related to the OCGS LRA.

3.0.3.2.21 Buried Piping Inspection (OCGS AMP B.1.26)

In OCGS LRA, Appendix B, Section B.1.26, the applicant stated that OCGS AMP B.1.26, "Buried Piping Inspection," is an existing plant program that is consistent with GALL AMP XI.M34, "Buried Piping and Tanks Inspection," with exceptions and enhancements.

3.0.3.2.21.1 Program Description

The applicant stated, in the OCGS LRA, that this program includes preventive measures to mitigate corrosion and periodic inspection of external surfaces for loss of material to manage the effects of corrosion on the pressure-retaining capacity of piping and components in a soil (external) environment. Preventive measures are in accordance with standard industry practices for maintaining external coatings and wrappings. External inspections of buried components will occur opportunistically when they are excavated during maintenance. Upon entering the period of extended operation, inspection of buried piping will be performed within ten years, unless an opportunistic inspection occurs within this ten-year period. The program will be enhanced as described below to provide assurance that buried piping and piping components will perform their intended function during the extended period of operation.

3.0.3.2.21.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.26 is consistent with GALL AMP XI.M34, with exceptions and enhancements.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.26, including OCGS program basis document PBD AMP B.1.26, ?Buried Piping Inspection," Rev. 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M34. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.26 and associated bases documents to determine consistency with GALL AMP XI.M34.

The project team reviewed those portions of the Buried Piping Inspection Program for which the applicant claims consistency with GALL AMP XI.M34 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's Buried Piping Inspection Program conforms to the recommended GALL AMP XI.M34, with the exceptions and enhancements described below.

3.0.3.2.21.3 Exceptions to the GALL Report

The applicant stated, in the OCGS LRA, the following exception to the GALL Report program elements:

Exception

Elements:	1. Scope of the Program 2. Preventive Actions 6. Acceptance Criteria
Exception:	Section X1.M.34, ?Buried Piping and Tanks Inspection," AMP only includes buried carbon steel piping; however, Oyster Creek has other material, such as stainless steel, aluminum, bronze and cast iron, in their buried piping program that will be managed as part of this AMP.

The GALL Report identified the following recommendations for the above program elements associated with the exception taken:

1. *Scope of the Program*: The GALL Report states that the program relies on preventive measures such as coating, wrapping and periodic inspection for loss of material caused by corrosion of the external surface of buried steel piping and tanks.

2. *Preventive Actions*: The GALL Report states that in accordance with industry practice, underground piping and tanks are coated during installation with a protective coating system, such as coal tar enamel with a fiberglass wrap and a kraft paper outer wrap, a polyolifin tape coating, or a fusion bonded epoxy coating to protect the piping from contacting the aggressive soil environment.

6. *Acceptance Criteria*: The GALL Report states that any coating and wrapping degradations are reported and evaluated according to site corrective actions procedures.

The project team asked the applicant if the buried pipe will be inspected within 10 years of the end of the current period of operation and during the first 10 years of the period of extended operation. The applicant replied that there will not be a focused inspection within 10 years of entering the period of extended operation because opportunistic inspections have occurred within this 10 year period. Also, a focused inspection will occur during the first 10 years of entering the period of extended operation unless an opportunistic inspection occurs during that time.

The project team also asked the applicant if each different kind of buried material will be inspected. The applicant stated that all of the different types of materials will not be examined. Rather, the inspections will be performed on a system with high likelihood of corrosion problems or systems that have a history of corrosion. The OCGS buried pipe aging management program contains aluminum, cast iron, stainless steel, and bronze in addition to the carbon steel. All but 25 feet to the aluminum pipe has been relocated to an above ground location. The remaining buried aluminum pipe is part of the condensate transfer system. The cast iron pipe is part of the fire protection system. The heating & process steam and roof drain & overboard discharge systems may contain stainless steel and bronze fittings that are coated. OCGS has never experienced any failures of these materials. To be conservative, OCGS has included these materials in the scope of the buried pipe aging management program.

The project team found the applicant's exception to the GALL Report to be acceptable after discussions with the applicant. In particular, the applicant explained that the bronze fittings are coated and that, with the exception of the aluminum pipe, none of the other materials has experienced any problems. Only a small portion of the aluminum pipe remains buried. On this basis, the project team found this exception acceptable.

3.0.3.2.21.4 Enhancements

The applicant stated, in the OCGS LRA, the following enhancement in order to meet the GALL Report program elements:

Elements:	1. Scope of the Program 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 6. Acceptance Criteria
Enhancement:	The Buried Piping Inspection aging management program will be enhanced to include Fire Protection components in the scope of the program. Inspection of buried piping within ten years of entering the period of extended operation will be conducted, unless an opportunistic inspection occurs within this ten-year period. Piping located inside the vault are in the scope of the program

The GALL Report identified the following recommendations for the above program elements associated with the exception taken:

1. *Scope of the Program*: The GALL Report stated that the program relies on preventive measures such as coating, wrapping and periodic inspection for loss of material caused by corrosion of the external surface of buried steel piping and tanks.

3. *Preventive Actions*: The GALL Report stated that in accordance with industry practice, underground piping and tanks are coated during installation with a protective coating system, such as coal tar enamel with a fiberglass wrap and a kraft paper outer wrap, a polyolifin tape coating, or a fusion bonded epoxy coating to protect the piping from contacting the aggressive soil environment.

4. *Detection of Aging Effects*: Inspections performed to confirm that coating and wrapping are intact are an effective method to ensure that corrosion of external surfaces has not occurred and the intended function is maintained.

Buried piping and tanks are opportunistically inspected whenever they are excavated during maintenance. When opportunistic, the inspections are performed in areas with the highest likelihood of corrosion problems, and in areas with a history of corrosion problems, within the areas made accessible to support the maintenance activity.

The applicant's program is to be evaluated for the extended period of operation. It is anticipated that one or more opportunistic inspections may occur within a ten-year period. Prior to entering the period of extended operation, the applicant is to verify that there is at least one opportunistic or focused inspection is performed within the past ten years.

Upon entering the period of extended operation, the applicant is to perform a focused inspection within ten years, unless an opportunistic inspection occurred within this ten-year period.

Any credited inspection should be performed in areas with the highest likelihood of corrosion problems, and in areas with a history of corrosion problems.

6. *Acceptance Criteria*: The GALL Report states for Element 6 that any coating and wrapping degradations are reported and evaluated according to site corrective actions procedures.

The applicant stated, in the OCGS LRA, that inspections will be performed to confirm that coating and wrapping are intact. These inspections are an effective method to ensure that corrosion of external surfaces has not occurred and the intended function is maintained. Inspections are performed to confirm that coating and wrapping are intact. External inspections of buried components will occur opportunistically when they are excavated during maintenance.

Buried piping will be opportunistically inspected whenever excavated for maintenance. The inspections will be performed on all of the areas made accessible to support the maintenance activity. Areas with the highest likelihood of corrosion problems, and areas with a history of corrosion problems have been identified in Topical Report ?Oyster Creek Underground Piping Program Description and Status".

There have been several yard excavation activities to date that have uncovered buried piping and inspections of the buried piping. Oyster Creek has performed focused inspection on their underground piping within the past ten years.

Several inspections have been performed on the ESW and SW systems, which have a high likelihood of corrosion problems and have a history of corrosion related problems. In addition other inspections and testing have been performed per the Technical Data Report TDR-829, ?Pipe Integrity Inspection Program," and Topical Report TR-116, ?Oyster Creek Underground Piping Program Description and Status."

Upon entering the period of extended operation inspection of buried piping will be performed within ten years, unless an opportunistic inspection occurs within this ten-year period.

Areas with the highest likelihood of corrosion problems, and areas with a history of corrosion problems have been identified in the above Topical Report. These are primarily in the ESW and SW systems. Inspections in these areas have been performed within the past ten years.

Additionally, Inservice Service Testing and monitoring for the ESW, SW, RBCCW, Fire Protection and Condensate Transfer systems are performed. Monitoring and trending from the performance of these tests can aid in the detection of system pipe leaks. Periodic leak testing and component inspections are being credited as well. Section XI Pressure Testing directs testing of buried cooling water piping for the detection of leaks. This pressure testing is performed via pump surveillances.

This enhancement adds additional components into the Buried Piping Inspection Program which is conservative. On this basis, the project team found this enhancement acceptable since when the enhancement is implemented, OCGS AMP B.1.26, "Buried Piping Inspection," will be consistent with GALL AMP XI.M34 and will provide additional assurance that the effects of aging will be adequately managed.

3.0.3.2.21.5 Operating Experience

The applicant stated, in the OCGS LRA and program basis document, that a review of plant operating experience at Oyster Creek shows that there has been only one underground leak that developed as a result of failure of the external portion of buried pipe. In 1992 the Service Water system developed a leak that resulted from failure of the external coating. The root cause evaluation determined that failure was due to improper original coating application. Subsequently, Oyster Creek initiated the Oyster Creek Underground Piping Program.

Additionally, in 1980, 1992 & 1996 leaks developed in buried aluminum Condensate Transfer pipe. As a result 90% of the AL piping was replaced and relocated aboveground. Subsequently, Oyster Creek initiated the Oyster Creek Underground Piping Program in which the inspection and modifications of the remaining 25 feet of buried AL Condensate Transfer system pipe are tracked. The primary contributor of the buried aluminum pipe at Oyster Creek high corrosion rate is galvanic corrosion. The galvanic mechanism is primarily due to the interaction between the aluminum pipe wall and the large copper grounding grind located on the west side of the plant. The grounding grid protects the main transformers and other electrical equipment and lies in the same footprint as the majority of the direct buried aluminum pipe; before it was replaced by above ground pipe. The dissimilar metals and moisture in the soil result in a high electrical/chemical potential that drive the galvanic corrosion. Corrosion occurs in local areas where the coating was not properly applied or has broken down. By moving the AL pipe to aboveground the aging mechanism of galvanic corrosion concern is eliminated. Additionally, the Oyster Creek Underground Piping Program tracks the inspection and modifications of the remaining 25 feet of buried AL Condensate Transfer system pipe. To date, there have been no other buried pipe leaks due to external degradation.

Although failure of buried piping has occurred, it has been determined that the integrity of the buried piping leaks were caused by degradation of the inside of the buried piping which is evaluated with the Open Cycle Closed Cooling Water aging management program. The existing Buried Piping Inspection aging management program has identified the loss of material due to general corrosion, pitting, crevice corrosion and MIC of ferrous materials and change in material properties on the external surfaces of buried pipe. The experience at Oyster Creek with the Buried Piping Inspection Program shows that the Buried Piping Inspection Program is effective in managing loss of material due to general corrosion, pitting, crevice corrosion and MIC of ferrous materials and change in material properties on the external surfaces of buried pipe.

Operating experience, both internal and external, is used in two ways at Oyster Creek to enhance plant programs, prevent repeat events, and prevent events that have occurred at other plants from occurring at Oyster Creek. The first way in which operating experience is used is through the Oyster Creek Operating Experience process. The Operating Experience process screens, evaluates, and acts on operating experience documents and information to prevent or mitigate the consequences of similar events. The second way is through the process for managing programs. This process requires the review of program related operating experience by the program owner.

Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that loss of material is being adequately managed in the Buried Piping

Inspection Program. The following examples of operating experience provide objective evidence that the Buried Piping Inspection Program is effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

The applicant has no exceptions to NUREG-1801. Element 3 and has added enhancements by including fire protection components to the scope of the program. In addition, the applicant has conducted numerous inspections and has identified key locations to inspect on a regular basis. When coating degradation or damage to pipe is discovered, corrective action is taken. About half of the ESW piping has been replaced and the remainder will be replaced before the period of extended operation.

Oyster Creek has performed numerous external inspections of their buried components between 1991 and present day. The results of these inspections have shown no significant external coating failures. Coatings have been repaired during these inspections in accordance with corporate procedures.

In 2004, 50% of the buried ESW and 10% of SW piping were replaced with new, coated piping. The project team asked the applicant when the remaining pipe will be replaced. In its letter dated May 1, 2006 (AmerGen Letter No. 2130-06-20328), the applicant committed to replace the previously un-replaced buried safety-related ESW piping prior to the period of extended operation. **This is a Audit Commitment 3.0.3.2.21-1.**

In 1993 an inspection of 20 feet of RBCCW was performed and the results showed that the external coating was in good condition..

In 1992 the Fire Protection system underground piping was inspected via excavation and some internal inspection. The External coating was in good condition as well as the internal carbon steel.

In 1980 the uncoated aluminum underground piping in the vicinity of the condensate storage tank was replaced. In 1991 and 1994 buried piping adjacent to the condensate transfer shack was determined to have severe corrosion during an inspection. As a result, a significant modification was performed which relocated aluminum piping aboveground, in tunnels or vaults. Currently 90% of all AL piping is located aboveground. The remaining buried AL pipe was inspected in 1993 and has an expected service life of 15-20 years. Action Request A2116126 has been submitted to perform and inspection of the remaining buried, uncoated AL pipe prior to December 2008. The remaining buried AL piping does have cathodic protection.

The operating experience of the Oyster Creek Buried Piping Inspection Program has shown objective evidence that the program has identified susceptible buried pipe locations and has created an monitoring program that has been effective in preventing failures prior to the loss of system intended function.

The operating experience of the Buried Piping Inspection Program did not show any adverse trend in performance. Problems identified would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. There is sufficient confidence that the implementation of the Buried Piping Inspection Program will effectively determine loss of material due to the manage the effects of corrosion on the pressure-retaining capacity of buried piping. Appropriate guidance for reevaluation, repair or replacement is provided for locations where loss of material was identified. Periodic self-assessments of the Buried Piping Inspection Program are performed to identify the areas that need improvement to maintain the quality performance of the program.

The project team reviewed the operating experience provided in the OCGS LRA, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant's Buried Piping Inspection Program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.2.21.6 <u>UFSAR Supplement</u>

The applicant provided its UFSAR Supplement for Buried Piping Inspection Program in OCGS LRA, Appendix A, Section A.1.26, which stated that the Buried Piping Inspection Program in OCGS LRA, Appendix A, Section A.2.2, which stated that the buried pipe inspection aging management program is an existing program that manages the external surface aging effects of loss of material for piping and piping system components in a soil (external) environment. The Oyster Creek buried piping activities consist of preventive and condition-monitoring measures to manage the loss of material due to external corrosion for piping, piping system components in the scope of license renewal that are in a soil (external)environment. The program will be enhanced to include inspection of buried piping within ten years of entering the period of extended operation, unless an opportunistic inspection occurs within this ten-year period. The program will also be enhanced to include the buried portions of the fire protection system and the piping located inside the vault in the scope of the program. External inspections of buried components will occur opportunistically when they are excavated during maintenance. Upon entering the period of extended operation, inspection of buried piping will be performed within ten years, unless an opportunistic inspection occurs within this ten-year period. Program enhancements will be implemented prior to entering the period of extended operation.

The project team also reviewed the applicant's license renewal commitment list in Appendix A of the OCGS LRA, and confirmed that the enhancements to this program are identified and will be implemented prior to the period of extended operation as item 26 of the commitments. The project team also reviewed the applicant's Audit Commitment (3.0.3.2.21-1) to replace the remaining ESW piping prior to the period of extended operation and this will also be implemented prior to the period of extended operation.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.26. Contingent upon the inclusion of audit commitment 3.0.3.2.21-1, the project team found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.2.21.7 <u>Conclusion</u>

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report, are consistent with the GALL Report. In addition, the project team has reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. Also, the project team has reviewed the enhancements and commitment 3.0.3.2.21-1 and determined that the implementation of the enhancements prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The project team also reviewed the UFSAR Supplement for this AMP and, contingent upon the inclusion of audit commitment 3.0.3.2.21-2, found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.22 ASME Section XI, Subsection IWE (OCGS AMP B.1.27)

In OCGS LRA, Appendix B, Section B.1.27, the applicant stated that OCGS AMP B.1.27, ?ASME Section XI, Subsection IWE," is an existing plant program that is consistent with GALL AMP XI.S1, "ASME Section XI, Subsection IWE," with an exception.

3.0.3.2.22.1 Program Description

The applicant stated, in the OCGS LRA, that this program provides for inspection of primary containment components and the containment vacuum breakers system piping and components. It is implemented through station plans and procedures and covers steel containment shells and their integral attachments; containment hatches and airlocks, seals and gaskets, containment vacuum breakers system piping and components, and pressure retaining bolting. The program includes visual examination and limited surface or volumetric examination, when augmented examination is required, to detect loss of material. The program also provides for managing loss of sealing for seals and gaskets, and loss of preload for pressure retaining bolting. Procurement controls and installation practices, defined in plant procedures, ensure that only approved lubricants and tension or torque are applied. The Oyster Creek program complies with Subsection IWE for steel containments (Class MC) of ASME Section XI, 1992 Edition including 1992 Addenda in accordance with the provisions of 10 CFR 50.55a.

3.0.3.2.22.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.27 is consistent with GALL AMP XI.S1, with an exception.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.27, including PBD-AMP-B.1.27, ?ASME Section XI, Subsection IWE," Revision 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.S1. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.27 and associated bases documents to determine consistency with GALL AMP XI.S1.

During the on-site audits on October 3-7, 2005, January 23-27, 2006, February 13-17, 2006, and April 19-20, 2006, the project team conducted an in-depth review of (1) the OCGS history of containment degradation due to corrosion; (2) the corrective actions taken at the time; (3) the current IWE augmented inspections, and other programs and activities to monitor/mitigate additional corrosion; and (4) the applicant’s license renewal commitments to manage aging of the degraded containment during the extended period of operation.

The project team had numerous discussions with the applicant's staff and submitted numerous questions to the applicant concerning containment degradation. The project team also reviewed a number of inspection reports, analysis reports, and official correspondence between the staff and the applicant, related to the containment degradation.

Through the audit process, the applicant made a number of significant new commitments to manage aging of the drywell shell. However, three issues remain unresolved. The project team's review of the applicant's initial license renewal commitments, the development of the applicant's new commitments, and the remaining unresolved issues are chronicled below, via the project team's questions and the applicant's responses.

The project team focused on the following four specific areas related to the containment degradation:

1) Water leakage from the refueling cavity into the annulus between the drywell and the shield wall;

2) Corrosion of the upper drywell region above the former sand bed region;

3) Corrosion of the former sand bed region of the drywell; and

4) Pitting Corrosion of the suppression chamber (torus).

The operating experience and proposed aging management activities for each of these areas were reviewed in detail, and additional information was obtained, as necessary, to facilitate a thorough evaluation of the applicant's aging management plans for the licence renewal period. The results of this detailed audit are documented in the following paragraphs. The discussion first documents the project team's audit questions, and the applicant's responses, in each of these four areas. Applicable question numbers from the audit question and answer database are also provided as a reference in the following sections. The project team's evaluation of the applicant's commitments for each of these four areas is provided at the end of this section.

Water Leakage from the Refueling Cavity

During the project team's discussions with the applicant's staff on October 4, 2005, concerning the OCGS ASME Section XI, Subsection IWE aging management program (AMP B.1.27), the applicant stated that a special coating is applied, prior to flooding the reactor for refueling, to prevent leakage into the annular space between the drywell shell and the concrete shield wall (refueling cavity). As a result, the applicant believes that water intrusion into the refueling cavity has been eliminated as a source for further degradation on the exterior surface of the drywell shell.

Since the applicant used this special coating to minimize water intrusion into the annulus between the drywell and the concrete shield wall, in audit question AMP-118, the project team asked the applicant to specifically identify whether it is committed to continue the use of this special coating as part of its refueling procedure through the extended period of operation. If not, the applicant was asked to identify what enhanced inspections will be conducted during the extended period of operation in order to monitor potential corrosion on the drywell exterior surface from the upper flange region to the sand bed region.

In its response, the applicant stated that the coating applied to the reactor cavity liner prior to refueling was not credited in the license renewal application as an aging management activity for managing loss of material due to corrosion on the exterior surfaces of the drywell. The coating was considered one of the many good practices implemented during the current term to minimize water intrusion in the annular space between the drywell shell and the drywell shield wall. The coating also facilitates decontamination of the reactor cavity post refueling. The applicant considered the credited ASME Section XI, Subsection IWE program (B.1.27), 10 CFR 50, Appendix J program (B.1.29), and the Protective Coating Monitoring and Maintenance Program (B.1.33), which is credited for monitoring protective coatings on the exterior surfaces of the drywell shell in the sand bed region, adequate to manage corrosion of the drywell shell.

During discussions with the applicant's technical staff on January 26, 2006, the applicant was asked to provide the technical basis for not crediting the use of the special coating as part of the Oyster Creek refueling procedure to mitigate water leakage into the annulus during the period of extended operation. In response, the applicant stated that the strippable coating has been effective in mitigating water intrusion into the annular space. The applicant committed to applying the strippable coating to the reactor cavity liner prior to flooding for refueling during the period of extended operation. This constitutes a new commitment not previously identified in the LRA, and was documented as a supplemental response to audit question AMP-118. In its letter dated April 4, 2006 (ML060970288), the applicant committed to the following: Consistent with current practice, a strippable coating will be applied to the reactor cavity liner to prevent water intrusion into the gap between the drywell shield wall and the drywell shell during periods when the refueling cavity is flooded. This commitment applies to refueling outages prior to and during the period of extended operation. This is **Audit Commitment 3.0.3.2.22-1.**

In reviewing program basis document PBD-AMP-B.1.27 for the applicant's ASME Section XI, Subsection IWE aging management program (B.1.27), the project team noted that, on page 7 of this document, the applicant stated that ?Under the current term, Oyster Creek is committed to the NRC to monitor the former sand bed region drains for water leakage. The commitment is to investigate the source of leakage, take corrective actions, evaluate the impact of the leakage and, if necessary, perform additional drywell inspections. This commitment will be implemented during the period of extended operation. This is a new commitment not previously identified in the LRA." In its letter dated April 4, 2006 (ML060970288), the applicant committed to the following: The reactor cavity seal leakage trough drains and the drywell sand bed region drains will be monitored for water leakage periodically. This is **Audit Commitment 3.0.3.2.22-2.**

The project team asked the applicant to describe this commitment in more detail, including the following information in audit question AMP-205:

- Is this continuous monitoring or outage monitoring?

- What have been the results of the current water leakage monitoring activities, with respect to investigating the source of leakage, taking corrective actions, evaluating the impact of the leakage and, if necessary performing additional drywell inspections?

- If no water leakage has been detected under the previous commitment, describe any preventive actions taken to alleviate the previous water leakage problem.

In its response, the applicant stated that the commitment for monitoring the sand bed drains is contained in an NRC Safety Evaluation Report (SER) transmitted in a letter dated November 1, 1995. This SER requested a commitment be made to perform inspections ?3 months after the discovery of any water leakage". Subsequent correspondence from GPUN clarified the commitment after discussions with the NRC. The commitment made and accepted by the NRC in a letter dated February 15, 1996, was to perform additional inspections of the drywell 3 months after discovery of any water leakage during power operation between scheduled drywell inspections. The requirement was not meant to apply to minor leakage associated with normal refueling activities. This in part is believed to be the present commitment and the commitment contained in the applicant's program basis document, PBD-AMP-B.1.27.

The applicant further stated in its response that there are no current formal leakage monitoring activities in place. Although the monitoring has not been formalized, the applicant stated that there has been no reported evidence of leakage from the former sand bed drains. The applicant also stated that Issue Report #348545 was submitted into the corrective action program when this was discovered. Corrective actions have been initiated to create recurring activities controlled with the work management process and procedures, to perform all future required inspections to meet the present day commitment. The applicant has stated that since there has been no reported leakage, there has been no need to investigate the source of leakage, take corrective actions, evaluate the impact of the leakage and, if necessary performing additional drywell inspections.

The applicant further stated that actions taken to alleviate the previous water leakage problem have been numerous, since the discovery of the leakage, and consequential drywell shell corrosion. Some of the significant actions consisted of inspections of the reactor cavity wall, remote visual inspection of the trough area below the reactor cavity bellows seal area, and subsequent repair of the trough area and clearing of the drain from the trough area. Clearing of the trough drain and repair of the trough assure routing of any leakage away from the drywell shell. In addition, a strippable coating is applied to the reactor cavity walls prior to filling the reactor cavity with water to minimize the likelihood of leakage into the trough area. These preventive actions have resulted in the lack of evidence of leakage over the years at the former sand bed drains.

Corrosion of the Upper Drywell above the Former Sand Bed Region

In reviewing the license renewal information for the upper region of the drywell shell, the project team noted that the applicant referred to the LRA Section 4.7.2 Drywell Corrosion TLAA evaluation for further discussion. In LRA Section 4.7.2, the applicant stated that the disposition of this TLAA is in accordance with 10 CFR 54.21(c)(1)(iii), and the Oyster Creek ASME Section XI, Subsection IWE aging management program is credited to address the drywell corrosion TLAA. In LRA Section 4.7.2, under Analysis, the applicant stated that the Oyster Creek ASME Section XI, Subsection IWE aging management program (B.1.27) ensures that the reduction in vessel thickness will not adversely affect the ability of the drywell to perform its safety function. The ASME Section XI, Subsection IWE aging management program ensures that the applicant performs periodic UT inspections at critical locations; performs calculations to track corrosion rates; projects vessel thickness based on conservatives corrosion rates; and demonstrates that the minimum required vessel thickness is maintained.

The applicant further stated in the LRA that inspections conducted since 1992 demonstrate that, as a result of corrective actions, the corrosion rates are very low or, in some cases, have been arrested. The drywell surfaces that were coated do not show signs of deterioration. Drywell vessel wall thickness measurements indicate there is substantial margin to the minimum wall thickness, even when projected to the year 2029 using conservative estimates of the corrosion rates. The applicant stated that continued assessment of the observed drywell vessel thickness ensures that timely action can be taken to correct degradation that could lead to loss of the intended function.

The project team reviewed the applicant's discussion of aging management activities for the upper region of the drywell shell and determined that additional information was needed pertaining to the augmented scope of IWE, as described above. The project team asked the applicant to provide the following information in audit question AMP-70:

> (a) Confirm that the stated activities are currently incorporated into, and implemented as part of the existing IWE program,
>
> (b) Provide the IWE implementing procedures for these activities,
>
> (c) Clarify the scope of these activities with regard to whether the sand bed region, in addition to the upper region of the drywell shell, is also included in the augmented scope; and whether other locations are regularly or randomly checked, to ensure that all degraded areas are known and monitored,
>
> (d) Provide the measured wall thickness history, the corrosion rate trending results, the projected remaining wall thickness at the end of the extended period of operation, and the CLB minimum required wall thickness for each location that is monitored,
>
> (e) Identify the current frequency of augmented UT inspections, corrosion rate calculations, and end-of-operating life thickness calculations, and
>
> (f) Identify the planned frequency of augmented UT inspections, corrosion rate calculations, and end-of-operating life thickness calculations for the extended period of operation.

In response, the applicant stated that Oyster Creek was committed to the drywell corrosion program in 1986 before implementation of IWE in September 9, 2001. The program elements, including periodic UT inspections at critical locations, performing calculations to track corrosion rates, projecting vessel thickness based on conservative corrosion rates, and demonstrating that the minimum required vessel thickness is maintained are now incorporated into IWE as an augmented inspection. The applicant provided procedures ER-AA-330, ER-AA-330-007, OC-6, and 2400-GMM-3900.52 for review.

The applicant further stated in its response that examination of the drywell interior surfaces in the former sand bed region is included as part of the ASME Section XI IWE inspections. The inspection of the exterior surfaces of the drywell in the sand bed region is included in the protective coatings and monitoring program (B.1.33).

The applicant also provided a tabulation of measured thicknesses for the monitored elevation of the upper region of the drywell shell, along with calculation 1302-187-E310-0037, which summarizes trending results, projected remaining wall thickness at the end of the extended period of operation, and the CLB minimum required thickness.

The applicant further stated that UT inspections are performed every other refueling outage, and that calculation 1302-187-E310-0037 provides the corrosion calculation, and end-of-operating life thickness calculation.

In its letter dated April 4, 2006 (ML060970288), the applicant committed to conduct UT thickness measurements in the upper regions of the drywell shell every other refueling outage at the same locations as are currently measured. This will be performed every other refueling outage prior to and during the period of extended operation. This is **Audit Commitment 3.0.3.2.22-3.**

In reviewing program basis document PBD-AMP-B.1.27 for the applicant's ASME Section XI, Subsection IWE aging management program, the project team noted that, in the discussion on pages 25 through 31 related to drywell corrosion above the sand bed region, the applicant stated that "Corrective action for these regions involved providing a corrosion allowance by demonstrating, through analysis, that the original drywell design pressure was conservative. Amendment 165 to the Oyster Creek Technical Specifications reduced the drywell design pressure from 62 psig to 44 psig. The new design pressure coupled with measures to prevent water intrusion into the gap between the drywell shell and the concrete will allow the upper portion of the drywell to meet ASME code requirements."

The project team asked the applicant to describe the measures to prevent water intrusion into the gap between the drywell shell and the concrete that will allow the upper portion of the drywell to meet ASME code requirements in audit question AMP-210. In addition, the applicant was further asked to clarify whether these measures to prevent water intrusion were credited for license renewal, and, if not, to clarify how ASME code requirements will be met during the extended period of operation.

In its response, the applicant stated that the measures taken to prevent water intrusion into the gap between the drywell shell and the concrete that will allow the upper portion of the drywell to maintain the ASME code requirements are the following:

1. Cleared the former sand bed region drains to improve the drainage path.

2. Replaced reactor cavity steel trough drain gasket, which was found to be leaking.

3. Applied stainless steel type tape and strippable coating to the reactor cavity during refueling outages to seal identified cracks in the stainless steel liner.

4. Confirmed that the reactor cavity concrete trough drains are not clogged

5. Monitored former sand bed region drains and reactor cavity concrete trough drains for leakage during refueling outages and plant operation.

The applicant further stated that Oyster Creek is committed to implement these measures during the period of extended operation.

Corrosion of the Former Sand Bed Region of the Drywell

In reviewing information for the sand bed region at the bottom of the drywell, the project team noted that, in the AMP B.1.27 discussion of operating experience, the applicant stated that sand was removed and a protective coating was applied to the shell to mitigate further corrosion. The coating is monitored periodically under LRA AMP B.1.33, Protective Coating Monitoring and Maintenance Program, which is discussed in Section 3.0.3.1.8 of this audit and review report. The project team reviewed LRA AMP B.1.33, and determined that the aforementioned coating is included within its scope. The project team noted that the discussion of operating experience in LRA AMP B.1.33 is similar to the discussion of operating experience in LRA AMP B.1.27.

The project team reviewed the applicant's aging management activities for the former sand bed region of the drywell shell and determined that additional information was needed pertaining to aging management of this region. In audit question AMP-071, the applicant was asked to provide the following information:

> (a) At the present time, is monitoring and maintenance of the coating in the sand bed region included in the scope of the current Protective Coating Monitoring and Maintenance Program or is it performed as part of the current ASME Section XI IWE program?
>
> (b) Provide the implementing procedure for this activity, and
>
> (c) Does license renewal aging management of the containment shell in the sand bed region include both the augmented IWE activities and the coating monitoring and maintenance activities under B.1.33? If only B.1.33 is credited, provide the technical basis for concluding that the augmented IWE activities are not necessary.

In response, the applicant stated that monitoring and maintenance of the coating in the former sand bed region is included in the scope of the Protective Coating Monitoring and Maintenance Program (AMP B.1.33). These activities are in accordance with specifications SP-1302-32-035 and SP-9000-06-003, which are included with program B.1.33.

The applicant further stated in its response that aging management of the sand bed region is not included in the augmented inspection required by ASME Section XI, Subsection IWE (AMP B.1.27). As stated in AMP B.1.27 operating experience, corrective actions that include cleaning and coating of the sand bed region implemented in 1992 have arrested corrosion. The coated surfaces were inspected in 1994, 1996, 2000, and 2004, and the inspection showed no coating failure or signs of degradation. Thus, the region is not subject to augmented inspection in accordance with IWE-1240. The coating will be inspected every other refueling outage during the period of extended operation consistent with NRC commitments for the current term.

As a result of discussions between the project team and the applicant on January 26, 2006 and April 20, 2006, the applicant supplemented its initial response to audit question AMP-071, to include the following:

- Oyster Creek will also perform periodic UT inspections of the drywell shell thickness in the sand bed region. Details are provided in response to audit questions AMP-141 and AMP-209.

- Oyster Creek will also enhance the Protective Coating Monitoring and Maintenance Program (B.1.33) to require inspection of the coating credited for corrosion (torus internal, vent system internal, sand bed region external) in accordance with ASME Section XI, Subsection IWE. Details are provided in the discussion of audit question AMP-188 later in this section.

- On April 20, 2006, Oyster Creek provided supplemental information on torus coating. Refer to AMP-072 response later in this section for this information.

Details of the enhancement to the Protective Coating Monitoring and Maintenance Program (B.1.33) and the project team's evaluation of this AMP are discussed in Section 3.0.3.1.8 of this audit and review report.

Based on the applicant's initial response to audit question AMP-071, the project team asked the applicant to provide its technical basis for not also crediting its ASME IWE program (AMP B.1.27) for managing loss of material due to corrosion in the former sand bed region of the drywell, in audit question AMP-141(a).

The applicant stated, in its response to audit question AMP-141(a) the following:

> That visual inspection of the containment drywell shell, conducted in accordance with ASME Section XI, Subsection IWE, is credited for aging management of accessible areas of the containment drywell shell. Typically this inspection is for internal surfaces of the drywell. The exterior surfaces of the drywell shell in the sand bed region for Mark I containment is considered inaccessible by ASME Section XI, Subsection IWE, thus, visual inspection is not possible for a typical Mark I containment, including Oyster Creek before the sand was removed from the sand bed region in 1992. After removal of the sand, an epoxy coating was applied to the exterior surfaces of the drywell shell in the sand bed region. The region was made accessible during refueling outages for periodic inspection of the coating. Subsequently, Oyster Creek performed periodic visual inspection of the coating in accordance with an NRC current licensing basis commitment. This commitment was implemented prior to implementation of ASME Section XI, Subsection IWE. As a result, inspection of the coating was conducted in accordance with the Protective Coating Monitoring and Maintenance Program. Oyster Creek's evaluation of this aging management program concluded the program is adequate to manage aging of the drywell shell in the sand bed region during the period of extended operation consistent with the current licensing basis commitment, and that inclusion of the coating inspection under the ASME IWE inspection is not required. However, Oyster Creek is amending this position and will commit to monitor the protective coating on the exterior surfaces of the drywell in the sand bed region in accordance with the requirements of ASME Section XI, Subsection IWE during the period of extended operation.

In its letter dated April 4, 2006 (ML060970288), the applicant committed to the following: Prior to the period of extended operation, AmerGen will perform additional visual inspections of the epoxy coating that was applied to the exterior surface of the drywell shell in the sand bed region, such that the coated surfaces in all 10 drywell bays will have been inspected at least once. In addition, the inservice inspection (ISI) program will be enhanced to require inspection of 100% of the epoxy coating every 10 years during the period of extended operation. These inspections will be performed in accordance with ASME Section XI, Subsection IWE. Performance of the inspections will be staggered such that at least three bays will be examined every other refueling outage. This commitment applies prior to the period of extended operation, and every ten years during the period of extended operation. This is **Audit Commitment 3.0.3.2.22-4.**

During discussions with the applicant's staff on October 4, 2005, regarding the augmented inspection conducted under ASME IWE, the applicant presented tabulated inspection results obtained from the mid-1980s to the present, to monitor the remaining drywell wall thickness in the cylindrical and spherical regions where significant corrosion of the outside surface was previously detected. The project team asked the applicant, in audit question AMP-141(b), to provide (1) a copy of these tabulated inspection results, (2) a list of the nominal design thicknesses in each region of the drywell, (3) a list of the minimum required thicknesses in each region of the drywell, and (4) a list of the projected remaining wall thicknesses in each region of the drywell in the year 2029.

The applicant stated, in its response to audit question AMP-141(b), that a tabulation of ultrasonic testing (UT) thickness measurement results in monitored areas of the drywell spherical region above the sand bed region and in the cylindrical region is included in the ASME Section XI, Subsection IWE program basis document (PBD-AMP-B.1.27). The tabulation contains information requested by the staff and is available for review during the AMP audit. The nominal design thicknesses of each region of the drywell are:

- Embedded shell below the sand bed region: 0.676 inches
- Sand bed region shell: 1.154 inches
- Spherical region at Elevation 23 feet to 51 feet: 0.770 inches
- Spherical region at Elevation 51 feet to 65 feet: 0.722 inches
- Transition from spherical to cylindrical region: 2.625 inches
- Cylindrical region: 0.640 inches

During the project team’s discussions with the applicant's staff on October 5, 2005, the applicant described the history and resolution of corrosion in the sand bed region. The applicant stated that, after discovery of corrosion in the sand bed region of the drywell, thickness measurements were taken from 1986 through 1992 to monitor the progression of wall loss. Remedial actions were completed in early 1993. At that time, the remaining wall thickness exceeded the minimum required thickness. The applicant concluded that it had completely corrected the conditions which led to the corrosion, and terminated its program to monitor the remaining wall thickness. At that time, the remaining plant operating life was expected to be no more than 16 years (end of the current license term).

As stated in the OCGS LRA, the applicant's aging management commitment for license renewal is limited to periodic inspection of the coating that was applied to the exterior surface of the drywell as part of the remedial actions. The applicant did not make a license renewal commitment in the LRA to measure wall thickness in the sand bed region in order to confirm the effectiveness of the remedial actions taken. To facilitate evaluation of the applicant's position, in audit question AMP-141(c), the project team asked the applicant to provide the following information:

- Tabulated inspection results obtained between 1986 and 1992 for the sand bed region.

- The nominal design thickness in the sand bed region.

- The minimum required thickness in the sand bed region.

- The minimum measured wall thickness in 1992.

- The minimum remaining corrosion allowance in 1992.

- A detailed technical basis for concluding that there is no need to confirm (through thickness measurements) that corrosion has been arrested in the sand bed region.

The applicant stated, in its response to audit question AMP-141(c), the following: In December 1992, with approval from the NRC a protective epoxy coating was applied to the outside surface of the drywell shell in the sand bed region to prevent additional corrosion in that area. UT thickness measurements taken in 1992, and in 1994, in the sand bed region from inside the drywell confirmed that the corrosion in the sand bed region has been arrested. Periodic inspection of the coating indicates that the coating in that region is performing satisfactorily with no signs of deterioration such as blisters, flakes, or discoloration, etc. Additional UT measurements, taken in 1996 from inside the drywell in the sand bed region showed no ongoing corrosion and provided objective evidence that corrosion has been arrested.

The applicant further stated that as a result of these UT measurements and the observed condition of the coating, the applicant concluded that corrosion has been arrested and monitoring of the protective coating alone, without additional UT measurements, will adequately manage loss of material in the drywell shell in the sand bed region. However to provide additional assurance that the protective coating is providing adequate protection to ensure drywell integrity, Oyster Creek will perform periodic confirmatory UT inspections of the drywell shell in the sand bed region. The initial UT measurements will be taken prior to entering the period of extended operation and then every 10 years thereafter. The UT measurements will be taken from inside the drywell at the same locations where the UT measurements were taken in 1996. This revises the license renewal commitment communicated to the NRC in a letter from C. N. Swenson Site Vice President, Oyster Creek Generating Station to U. S. Nuclear Regulatory Commission, "Additional Commitments Associated with Application for renewed Operating License – Oyster Creek Generating Station", dated December 9, 2005. This letter commits to one-time inspection to be conducted prior to entering the period of extended operation.

As a result of discussions between the project team and the applicant's staff on April 20, 2006, the applicant supplemented its response to audit question AMP-141(c). The applicant stated that Oyster Creek is committed to the following: ?During the initial UT inspections of the sand bed region from inside the drywell, conducted prior to entering the period of extended operation, an attempt will be made to locate and evaluate some of the locally thinned areas identified in the 1992 inspection from the exterior of the drywell. This will be performed using the latest UT methodology with existing shell paint in place. The UT thickness measurements for these locally thinned areas may be taken from either inside the drywell or outside the drywell (sand bed region) to limit radiation dose to as low as reasonably achievable (ALARA)."

In its letter dated April 4, 2006, the applicant committed to the following:

> Ultrasonic Testing (UT) thickness measurements of the drywell shell in the sand bed region will be performed on a frequency of every 10 years. The initial inspection will occur prior to the period of extended operation. The UT measurements will be taken from the inside of the drywell at the same locations where UT measurements were performed in 1996. The inspection results will be compared to previous results. Statistically significant deviations from the 1992, 1994, and 1996 UT results will result in corrective actions that include the following: a) perform additional UT measurements to confirm the readings; b) notify NRC within 48 hours of confirmation of the identified condition; c) conduct visual inspection of the external surface in the sand bed region in areas where any unexpected corrosion may be detected; d) perform engineering evaluation to assess the extent of condition and to determine if additional inspections are required to assure drywell integrity; and e) perform operability determination and justification for operation until next inspection. These actions will be completed prior to restart from the associated outage.

This is **Audit Commitment 3.0.3.2.22-5.**

Also, in its letter dated May 1, 2006 (AmerGen Letter No. 2130-06-20328), the applicant committed to the following: During the next UT inspections to be performed on the drywell sand bed region (reference AmerGen 4/4/06 letter to NRC), an attempt will be made to locate and evaluate some of the locally thinned areas identified in the 1992 inspection from the exterior of the drywell. This testing will be performed using the latest UT methodology with existing shell paint in place. The UT thickness measurements for these locally thinned areas may be taken from either inside the drywell or outside the drywell (sand bed region) to limit radiation dose to as low as reasonably achievable (ALARA). This is **Audit Commitment 3.0.3.2.22-6**.

In reviewing program basis document PBD-AMP-B.1.27 for the applicant's ASME Section XI, Subsection IWE aging management program (B.1.27), the project team noted that, on page 17 of this document, the applicant stated that, ?As discussed with NRC staff during the AMP audit, Oyster Creek will perform one-time UT thickness measurements of the drywell shell, in the sand bed region, to confirm that the protective coating is effective. The UT measurements will be taken from inside the drywell at the same or approximate locations measured in 1996. This constitutes a new commitment that will be implemented prior to entering the period of extended operation."

The project team asked the applicant to provide additional information related to this new commitment, in audit question AMP-209, including the following:

- Has this been added to the scope of the one time inspection program (AMP B.1.24)?
- How will this commitment be tracked and implemented?
- Are the locations selected for one-time inspection those that had the minimum remaining thickness based on prior UT results, and if not, explain the technical basis for why the selected locations are adequate?
- What steps will be taken if the current conclusion, that corrosion has been arrested, is not confirmed by the one-time inspection?

In its response, the applicant stated that the one-time inspection commitment has not been added to One-Time Inspection Program (AMP B.1.24). As discussed with NRC staff on January 26, 2006, Oyster Creek will perform periodic UT inspections during the period of extended operation instead of a one-time inspection. The initial UT inspections will occur prior to entering the period of extended operation and every 10 years thereafter. The project team noted that this is Audit Commitment 3.0.3.2.22-5, which was discussed previously in this section of the audit and review report.

The applicant further stated in its response that this commitment will be tracked in accordance with Oyster Creek commitment tracking process. Additionally, the commitment will be included in a revision to the Appendix A.5 commitment list, item #27, which will be submitted to the NRC and incorporated in the UFSAR supplement. Implementation of the commitment will be through the Oyster Creek ASME Section XI, Subsection IWE program.

The applicant stated the locations selected for UT measurements are the same as those inspected using UT measurements in 1996 and include the thinnest measured area. If the current conclusion that corrosion has been arrested is not confirmed by UT measurements taken prior to entering the period of extended operation, Oyster Creek is committed to take corrective actions defined in Audit Commitment 3.0.3.2.22-5.

The project team asked the applicant to provide a discussion of the scope of the current coating inspection program and the license renewal commitment, in the second part of audit question AMP-209, including the following information:

- What percent of the total circumference is inspected during each inspection?
- How many years and how many inspections does it take to complete a 360 degree inspection of the sand bed region?
- Whether a complete 360 degree inspection been completed yet, and
- How many complete 360 degree inspections will be completed during the license renewal period?

In its response to the second part of audit question AMP-209, the applicant stated that protective coatings on the exterior surfaces of the drywell shell in the sand bed region are monitored in accordance with the Protective Coating Monitoring and Maintenance Program (B.1.33). The current program requires visual inspection of the coating in accordance with engineering specification IS-328227-004. Inspection criteria are not specifically provided by the specification. However, inspections are performed by individuals qualified to perform coating inspections. Acceptance criteria provided in the specification are that any identified coating defects shall be submitted for engineering evaluation. The inspection frequency is every other refueling outage.

The applicant further stated in its response that, as discussed with NRC Staff, the existing protective coating monitoring and maintenance aging management program (AMP B.1.33) does not currently invoke all of the requirements of ASME Section XI, Subsection IWE. The applicant also stated that Oyster Creek is committed to enhancing the program to incorporate coated surfaces inspection requirements specified in ASME Section XI, Subsection IWE. In response to NRC Question AMP-188, Oyster Creek provided specific enhancements that will be made to the program as follows:

> Sand bed Region external coating inspections will be per Examination Category E-C (augmented examination) and will require VT-1 visual examinations per IWE-3412.1.
>
> a. The inspected area shall be examined (as a minimum) for evidence of flaking, blistering, peeling, discoloration, and other signs of distress.
>
> b. Areas that are suspect shall be dispositioned by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122.
>
> c. Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of engineering evaluation."

The applicant further stated in its response that the coated surface of the drywell in the sand bed region is divided into 10 bays that constitute 360 degrees. The current program requires inspection of coatings in at least 2 bays every other refueling outage. Certain bays were considered critical and have been inspected more than once. Inspection of 5 out of 10 bays (50%) has been completed to date.

The applicant further stated that for license renewal, Oyster Creek is committed to inspect the remaining 5 bays prior to entering the period of extended operation. This will result in a complete (100%) coating inspection of all the 10 bays (360 degree) prior to entering the period of extended operation.

The applicant also stated that Oyster Creek is committed to inspect the coating in accordance with ASME Section XI, Subsection IWE. Thus, inspection of 100% of the coating will be completed during each Containment ISI 10-Year Interval. Inspections will be conducted every other refueling outage during which at least 3 bays (30% of the coating minimum) will be examined. The applicant therefore expects to inspect 100% of the coating twice during the period of extended operation. The inspections will be conducted in accordance with the enhanced Protective Coating Monitoring and Maintenance Program (B.1.33), including enhancements discussed in NRC Audit Question AMP-188.

The project team noted that the above commitments are included as part of Audit Commitment 3.0.3.2.22-4, which was discussed previously in this section of the audit and review report.

The project team also noted that pages 25 through 31of the program basis document (PBD-AMP-B.1.27) for the applicant’s ASME Section XI, Subsection IWE aging management program, presented a discussion of the OCGS operating experience. This document stated that "As a result of the presence of water in the sand bed region, extensive UT thickness measurements (about 1000) of the drywell shell were taken to determine if degradation was occurring. These measurements corresponded to known water leaks and indicated that wall thinning had occurred in this region."

The project team asked the applicant [audit question AMP-210] to explain the above statement, and clarify whether the water leaks referred to were limited to only a portion of the circumference, and whether wall thinning was found only in these areas.

In its response, the applicant stated that this statement was not meant to indicate that water leaks were limited to only a portion of the circumference. The statement was meant to reflect the fact that water leakage was observed coming out of certain sand bed region drains and those locations were suspect of wall thinning. Wall thinning was not limited to the areas where water leakage from the drains was observed. Wall thinning occurred in all areas of the sand bed region based on UT measurements and visual inspection of the area conducted after the sand was removed in 1992. However, the degree of wall thinning varied from location-to-location. For example, 60% of the measured locations in the sand bed region (bays 1, 3, 5, 7, 9, and 15) indicate that the average measured drywell shell thickness is nearly the same as the design nominal thickness, and that these locations experienced negligible wall thinning; whereas bay 19A experienced approximately 30% reduction in wall thickness.

The project team also noted the following statement in PBD-AMP-B.1.27; "After sand removal, the concrete surface below the sand was found to be unfinished with improper provisions for water drainage. Corrective actions taken in this region during 1992 included; (1) cleaning of loose rust from the drywell shell, followed by application of epoxy coating and (2) removing the loose debris from the concrete floor followed by rebuilding and reshaping the floor with epoxy to allow drainage of any water that may leak into the region. UT measurements taken from the outside after cleaning verified loss of material projections that had been made based on measurements taken from the inside of the drywell. There were, however, some areas thinner than projected; but in all cases engineering analysis determined that the drywell shell thickness satisfied ASME code requirements." The project team asked the applicant to describe the "concrete surface below the sand" that is discussed in this statement in audit question AMP-210.

In its response, the applicant stated that the concrete surface below the sand was intended to be shaped to promote flow toward each of the five sand bed drains. However once the sand was removed the applicant discovered that the floor was not properly finished and shaped as required to permit proper drainage. There were low points, craters, and rough surfaces that could allow moisture to pool instead of flowing smoothly toward the drains. These concrete surfaces were refurbished to fill low areas, smooth rough surfaces, and coat these surfaces with epoxy coating to promote improved drainage. The drywell shell at juncture of the concrete floor was sealed with an elastomer to prevent water intrusion into the embedded drywell shell.

The project team asked the applicant to provide the following information related to inspections of the drywell sand bed region in audit question AMP-210:

> (1) Identify the minimum recorded thickness in the sand bed region from the outside inspection, and the minimum recorded thickness in the sand bed region from the inside inspections. Is this consistent with previous information provided verbally? (.806" minimum)
>
> (2) What was the projected thickness based on measurements taken from the inside?
>
> (3) Describe the engineering analysis that determined satisfaction of ASME code requirements and identify the minimum required thickness value. Is this consistent with previous information provided verbally? (.733" minimum)
>
> (4) Is the minimum required thickness based on stress or buckling criteria?
>
> (5) Reconcile and compare the thickness measurements provided in (1) and (3) above with the 0.736" minimum corroded thickness that was used in the NUREG-1540 analysis of the degraded Oyster Creek sand bed region.

In its response, the applicant stated that the minimum recorded thickness in the sand bed region from outside inspection is 0.618 inches. The minimum recorded thickness in the sand bed region from inside inspections is 0.603. These minimum recorded thicknesses are isolated local measurement and represent a single point UT measurement.

On April 19, 2006, the applicant supplemented its response to audit question AMP-210, stating that the lowest recorded reading was 0.603 in December 1992. The applicant stated that a review of the previous readings for the period 1990 thru 1992, and two subsequent readings taken in September 1994 and 1996, show this point should not be considered valid. The average reading for this point taken in 1994 and 1996 was 0.888 inches. Point 14 in location 17D was the next lowest value of 0.646 inches, recorded during the 1994 outage. A review of readings at this same point, taken during the period from 1990 through 1992, and subsequent readings taken in 1996 are consistent with this value. Thus, the minimum recorded thickness in the sand bed region from inside inspections is 0.646 inches, instead of 0.603 inches.

The applicant further stated in its response that the 0.806 inches thickness provided to the staff verbally is an average minimum general thickness calculated based on 49 UT measurements taken in an area that is approximately 6"x 6". Thus, the two local isolated minimum recorded thicknesses cannot be compared directly to the general thickness of 0.806". The 0.806" minimum average thickness verbally discussed with the staff during the AMP audit was recorded in location 19A in 1994. Lower minimum average thickness values were recorded at the same location in 1991 (0.803") and in September 1992 (0.800"). However, the three values are within the tolerance of +/- 0.010" discussed with the staff.

The applicant further stated in its response that the minimum projected thickness depends on whether the trended data is before or after 1992, as demonstrated by corrosion trends provided in response to audit question AMP-356. For license renewal, using corrosion rate trends after 1992 is appropriate because of corrosion mitigating measures, such as removal of the sand and coating of the shell. Then, using corrosion rate trends based on 1992, 1994, and 1996 UT data; and the minimum average thickness measured in 1992 (0.800"), the minimum projected average thickness through 2009 and beyond remains approximately 0.800 inches. The projected minimum thickness during and through the period of extended operation will be reevaluated after UT inspections that will be conducted prior to entering the period of extended operation, and after the periodic UT inspection every 10 years thereafter.

The applicant also stated in its response that the engineering analysis that demonstrated compliance to ASME code requirements was performed in two parts, stress and stability analysis with sand, and stress and stability analyses without sand. The analyses are documented in GE Reports Index No. 9-1, 9-2, 9-3, and 9-4, which were transmitted to the NRC in December 1990 and in 1991, respectively. Index No. 9-3 and 9-4 were revised later to correct errors identified during an internal audit, and were resubmitted to the staff in January 1992. The analyses are briefly described below.

> Summary of Analyses:
>
> The drywell shell thickness in the sand bed region is based on stability analysis without sand. As described in detail in attachment 1 & 2, the analysis is based on a 36-degree section model that takes advantage of symmetry of the drywell with 10 vents. The model includes the drywell shell from the base of the sand bed region to the top of elliptical head and the vent and vent header. The torus is not included in this model because the bellows provide a very flexible connection, which does not allow significant structural interaction between the drywell and the torus. The analysis conservatively assumed that the shell thickness in the entire sand bed region has been reduced uniformly to a thickness of 0.736 inches.

The applicant's response further stated the following:

> The basic approach used in the buckling evaluation follows the methodology outlined in ASME Code Case N-284, Revision 0, which was reconciled later with Revision 1 of the Code Case. Following the procedure of this Code Case, the allowable compressive stress is evaluated in three steps. In the first step, a theoretical buckling stress is determined, and secondly modified using appropriate capacity and plasticity reduction factors. In the final step, the allowable compressive stress is obtained by dividing the buckling stress calculated in the second step by a safety factor of 2.0 for Design and Level A & B service conditions, and 1.67 for Level C service conditions.
>
> Using the approach described above, the analysis shows that for the most severe design basis load combinations, the limits of ASME Section III, Subsection NE 3213.10 are fully met. As described above, the buckling analysis was performed assuming a uniform general thickness of the sand bed region of 0.736 inches. However the UT

measurements identified isolated, localized areas where the drywell shell thickness is less than 0.736 inches. Acceptance for these areas was based on engineering calculation C-1302-187-5320-024.

The calculation uses a ?Local Wall Acceptance Criterion". This criterion can be applied to small areas (less than 12" by 12"), which are less than 0.736" thick as long as the small 12" by 12" area is at least 0.536" thick. However, the calculation does not provide additional criteria as to the acceptable distance between multiple small areas. For example, the minimum required linear distances between a 12" by 12" area thinner than 0.736" but thicker than 0.536", and another 12" by 12" area thinner than 0.736" but thicker than 0.536" were not provided.

The actual data for two bays (13 and 1) show that there are more than one 12" by 12" areas thinner than 0.736" but thicker than 0.536". Also, the actual data for two bays shows that there are more than one 2 ½'" diameter areas thinner than 0.736" but thicker than 0.490". Acceptance is based on the following evaluation.

The effect of these very local wall thickness areas on the buckling of the shell requires some discussion of the buckling mechanism in a shell of revolution under an applied axial and lateral pressure load. To begin the discussion, we will describe the buckling of a simply supported cylindrical shell under the influence of lateral pressure and axial load. As described in chapter 11 of the Theory of Elastic Stability, Second Edition, by Timoshenko and Gere, thin cylindrical shells buckle in lobes in both the axial and circumferential directions. These lobes are defined as half wave lengths of sinusoidal functions. The functions are governed by the radius, thickness and length of the cylinder. If we look at a specific thin-walled cylindrical shell both the length and radius would be essentially constants and if the thickness was changed locally the change would have to be significant and continuous over a majority of the lobe so that the compressive stress in the lobe would exceed the critical buckling stress under the applied loads, thereby causing the shell to buckle locally. This approach can be easily extrapolated to any shell of revolution that would experience both an axial load and lateral pressure as in the case of the drywell. This local lobe buckling is demonstrated in a GE Letter Report ?Sandbed Local Thinning and Raising the Fixity Height Analysis" where a 12 x 12 square inch section of the drywell sand bed region is reduced by 200 mils and a local buckle occurred in the finite element eigenvalue extraction analysis of the drywell. Therefore, to influence the buckling of a shell the very local areas of reduced thickness would have to be contiguous and of the same thickness. This is also consistent with Code Case N-284 in Section -1700 which indicates that the average stress values in the shell should be used for calculating the buckling stress. Therefore, an acceptable distance between areas of reduced thickness is not required for an acceptable buckling analysis except that the area of reduced thickness is small enough not to influence a buckling lobe of the shell. The very local areas of thickness are dispersed over a wide area with varying thickness and as such will have a negligible effect on the buckling response of the drywell. In addition, these very local wall areas are centered about the vents, which significantly stiffen the shell. This stiffening effect limits the shell buckling to a point in the shell sand bed region which is located at the midpoint between two vents.

The acceptance criteria for the thickness of 0.49 inches confined to an area less than 2½ inches in diameter experiencing primary membrane + bending stresses is based on ASME Code, Section III, Subsection NE, Class MC Components, Paragraphs

NE-3213.2 Gross Structural Discontinuity, NE-3213.10 Local Primary Membrane Stress, NE-3332.1 Openings not Requiring Reinforcement, NE-3332.2 Required Area of Reinforcement and NE-3335.1 Reinforcement of Multiple Openings. The use of Paragraph NE-3332.1 is limited by the requirements of Paragraphs NE- 3213.2 and NE-3213.10. In particular NE-3213.10 limits the meridional distance between openings without reinforcement to 2.5 x (square root of Rt). Also Paragraph NE-3335.1 only applies to openings in shells that are closer than two times their average diameter.

The implications of these paragraphs are that shell failures at these locations from primary stresses produced by pressure cannot occur, provided openings in shells have sufficient reinforcement. The current design pressure of 44 psig for drywell requires a thickness of 0.479 inches in the sand bed region of the drywell. A review of all the UT data presented in Appendix D of the calculation indicates that all thicknesses in the drywell sand bed region exceed the required pressure thickness by a substantial margin. Therefore, the requirements for pressure reinforcement specified in the previous paragraph are not required for the very local wall thickness evaluation presented in Revision 0 of Calculation C-1302-187-5320-024.

Reviewing the stability analyses provided in both the GE Report 9-4 and the GE Letter Report ?Sand bed Local Thinning and Raising the Fixity Height Analysis," and recognizing that the plate elements in the sand bed region of the model are 3" x 3", it is clear that the circumferential buckling lobes for the drywell are substantially larger than the 2 ½ inch diameter very local wall areas. This, combined with the local reinforcement surrounding these local areas, indicates that these areas will have no impact on the buckling margins in the shell. It is also clear from the GE Letter Report that a uniform reduction in thickness of 27% to 0.536" over a one square foot area would only create a 9.5% reduction in the load factor and theoretical buckling stress for the whole drywell, resulting in the largest reduction possible. In addition to the reported result for the 27% reduction in wall thickness, a second buckling analysis was performed for a wall thickness reduction of 13.5% over a one square foot area, which only reduced the load factor and theoretical buckling stress by 3.5% for the whole drywell, resulting in the largest reduction possible. To bring these results into perspective, a review of the NDE reports indicate there are 20 UT measured areas in the whole sand bed region that have thicknesses less than the 0.736 inch thickness used in GE Report 9-4, which cover a conservative total area of 0.68 square feet of the drywell surface with an average thickness of 0.703" or a 4.5% reduction in wall thickness. Therefore, to effectively change the buckling margins on the drywell shell in the sand bed region, a reduced thickness would have to cover approximately one square foot of shell area at a location in the shell that is most susceptible to buckling with a reduction in thickness greater than 25%. This leads to the conclusion that the buckling of the shell is unaffected by the distance between the very local wall thicknesses; in fact these local areas could be contiguous provided their total area did not exceed one square foot and their average thickness was greater than the thickness analyzed in the GE Letter Report, and provided the methodology of Code Case N-284 was employed to determine the allowable buckling load for the drywell. Furthermore, all of these very local wall areas are centered about the vents, which significantly stiffen the shell. This stiffening effect limits the shell buckling to a point in the shell sand bed region, which is located at the midpoint between two vents.

As part of its response, the applicant also stated that the minimum thickness of 0.733" is not correct. The correct minimum thickness is 0.736". The minimum required thickness for the sand bed region is controlled by buckling.

The applicant also stated in its response that it cannot reconcile the difference between the current (lowest measured) of 0.736" in NUREG-1540 and the minimum measured thickness of 0.806 inches discussed with the staff. Perhaps the value in NUREG-1540 should be labeled minimum required by the Code, as documented in several correspondences with the staff, instead of lowest measured. In a letter dated September 15, 1995, GPU provided the staff a table that lists sand bed region thicknesses. The table indicates that nominal thickness is 1.154". The minimum measured thickness in 1994 is 0.806", and the minimum thickness required by Code is 0.736". These thicknesses are consistent with those discussed with the staff during the AMP/AMR audit.

The project team also noted the following statement in PBD-AMP-B.1.27; "Evaluation of UT measurements taken from inside the drywell, in the former sand bed region, in 1992, 1994, and 1996 confirmed that corrosion is mitigated. It is therefore concluded that corrosion in the sand bed region has been arrested and no further loss of material is expected. Monitoring of the coating in accordance with the Protective Coating Monitoring and Maintenance Program, will continue to ensure that the containment drywell shell maintains its intended function during the period of extended operation."

The project team compared the statement above from PBD-AM-B.1.27 with a discussion from NUREG-1540, published in April 1996, which includes the following statements related to corrosion of the Oyster Creek sand bed region: (page vii) "However, to assure that these measures are effective, the licensee is required to perform periodic UT measurements." and (page 2) "As assurance that the corrosion rate is slower than the rate obtained from previous measurements, GPU is committed to make UT measurements periodically." In audit question AMP-210, the applicant was asked to reconcile the aging management commitment (one-time UT inspection and monitoring of the condition of the coating) with the apparent recommendation/ commitment documented in NUREG-1540.

In its response, the applicant stated that its review of NUREG-1540, page 2, indicates that the statements appear to be based on a 1991 or 1993 GPU commitment to perform periodic UT measurements. In fact, UT thickness measurements were taken in the sand bed region from inside the drywell in 1992 and 1994. The trend of the UT measurements indicates that corrosion has been arrested. GPU informed NRC in a letter dated September 15, 1995 that UT measurements will be taken one more time, in 1996, and the epoxy coating will be inspected in 1996 and, as a minimum, again in 2000. The UT measurements were taken in 1996, per the commitment, and confirmed the corrosion rate trend of 1992 and 1994. The results of the 1992, 1994, and 1996 UT measurements were provided to the staff during the AMP/AMR audits.

The applicant also stated that in response to a GPU September 15, 1995 letter, NRC staff found the proposed changes to the sand bed region commitments (i.e. no additional UT measurements after 1996) reasonable and acceptable. This response is documented in a November 1, 1995, Safety Evaluation for the Drywell Monitoring Program. For license renewal, Oyster Creek had not committed to perform UT inspection of the drywell shell in the sand bed region. However, in response to an NRC audit question, Oyster Creek revised the commitment to perform UT inspections periodically. The initial inspection will be conducted prior to entering the period of extended operation and additional inspections will be conducted every 10 years thereafter. The UT measurements will be taken from inside the drywell at same locations as 1996 UT campaign. This is Audit Commitment 3.0.3.2.22-5, which was discussed previously in this section.

To assist the project team in its detailed assessment of the condition of the sand bed region, in audit question AMP-356, the project team asked the applicant to provide the following additional information:

> (1) Identify the specific locations around the circumference in the former sand bed region where UT thickness readings have been and will be taken from inside containment. Confirm that all points previously recorded will be included in future inspections.
>
> (2) Describe the grid pattern at each location (meridional length, circumferential length, grid point spacing, total number of point readings), and graphically locate each grid pattern within the former sand bed region.
>
> (3) For each grid location, submit a graph of remaining thickness versus time, using all inspection results obtained since the initiation of the program (both prior to and following removal of the sand and application of the external coating).
>
> (4) Clearly describe the acceptance criteria applied to each array of point thickness readings, including both global (entire array) and local (subregion of array) acceptance criteria.

In its response, the applicant stated that the circumference of the drywell is divided into 10 bays, designated as bays 1, 3, 5, 7, 9, 11,13, 15, 17, and 19. UT thickness readings have been taken in each bay at one or more locations. The specific locations around the circumference in the former sand bed region where UT thickness reading have been taken from inside containment are bay 1D, 3D, 5D, 7D, 9A, 9D, 11A, 11C, 13A, 13C, 13D, 15A, 15D, 17A, 17D, 17/19 Frame, 19A, 19B, and 19C. For each location, UT measurements were taken centered at elevation 11’-3". These represent the locations where UT measurements were taken in 1992, 1994, and 1996. In addition, UT measurements were taken one time inside 2 trenches excavated in drywell floor concrete. The purpose of these UT measurements is to determine the extent of corrosion in the lower portions of the sand bed region prior to removing the sand and making accessible for visual inspection. Future UT thickness measurements will be taken at the same locations as those inspected in 1996, in accordance with the Oyster Creek commitment documented in response to audit question AMP-141. This is Audit Commitment 3.0.3.2.22-5, which was discussed previously in this section.

The applicant further stated in its response that, for locations where the initial investigations found significant wall thinning (9D, 11A, 11C, 13A, 13D, 15D, 17A, 17D, 17/19 Frame, 19A, 19B, and 19C) the grid pattern consists of a 7 x 7 grid centered at elevation 11’-3 (meridian) and centered at the centerline of the tested location within each bay, which consists of a 6"x 6" square template. The grid spacing is 1" on center. There are 49 point readings. For locations where the initial investigations found no significant wall thinning (1D, 3D, 5D, 7D, 9A, 13C, and 15A) the grid pattern consists of 1 x 7 grid centered at elevation 11’-3" (meridian) on 1" centers.

The applicant further stated that a graph representing the remaining thickness versus time using UT readings since the initiation of the program (both prior to and following removal of the sand and application of the external coating) for locations 9D, 11A, 11C, 13A, 13D, 15D, 17A, 17D, 17/19, 19A, 19B, and 19C is included in a graph provided to the project team. Other locations (i.e. 1D, 3D, 5D, 7D, 9A, 13C, and 15A) are not included because wall thinning is not significant and the trend line will be essentially a straight line.

The applicant stated that the methodology and acceptance criteria that were applied to each grid of point thickness readings, including both global (entire array) evaluation and local (subregion of array) are described in engineering specification IS-328227-004 and in calculation No. C-1302-187-5300-011. The applicant also stated that these documents were submitted to the NRC in a letter dated November 26, 1990 and provided to the staff during the AMP/AMR audit. A brief summary of the methodology and acceptance criteria is described below.

> Summary of Methodology and Acceptance Criteria:
>
> The initial locations where corrosion loss was most severe in 1986 and 1987 were selected for repeat inspection over time to measure corrosion rate. For locations where the initial investigations found significant wall thinning, UT inspection consisted of 49 individual UT data points equally spaced over a 6"x 6" area. Each new set of 49 values was then tested for normal distribution. The mean values of each grid were then compared to the required minimum uniform thickness criteria of 0.736. In addition, each individual reading was compared to the local minimum required criteria of 0.49". The basis for the required minimum uniform thickness criteria and the local minimum required criteria is provided in response to a previous NRC audit question.
>
> A decrease in the mean value over time is representative of corrosion. If corrosion does not exist, the mean value will not vary with time except for random variations in the UT measurements. If corrosion is continuing, the mean thickness will decrease linearly with time. Therefore, the curve fit of the data is tested to determine if linear regression is appropriate, in which case the corrosion rate is equal to the slope of the line. If a slope exists, then upper and lower 95% confidence intervals of the curve fit are calculated. The lower 95% confidence interval is then projected into the future and compared to the required minimum uniform thickness criteria of 0.736.
>
> A similar process is applied to the thinnest individual reading in each grid. The curve fit of the data is tested to determine if linear regression is appropriate. If a slope exists, then the lower 95% confidence interval is then projected into the future and compared to the required minimum local thickness criteria of 0.49".

The project team asked the applicant to provide the following information related to the evaluation of the results obtained in the next UT inspection of the sand bed region in audit question AMP-357:

> (1) When a new set of point thickness readings is taken is the former sand bed region, prior to entering the LR period, what will be the quantitative acceptance criteria for concluding that corrosion has or has not occurred since the last inspection in 1996.
>
> (2) If additional corrosion is detected in the upcoming inspection, describe in detail the augmented inspections and other steps that will be taken to evaluate the extent of the corrosion, and describe the approach to ensuring the continued structural adequacy of the containment.

In its response, the applicant stated that the new set of UT measurements for the former sand bed region will be analyzed using the same methodology used to analyze the 1992, 1994, and 1996 UT data. The results will then be compared to the 1992, 1994, and 1996 UT results to confirm the previous no corrosion trend. Because of surface roughness of the exterior of the drywell shell, experience has shown that UT measurements can vary significantly unless the UT instrument is positioned on the exact point as the previous measurements. Thus, acceptance criteria will be based on the standard deviation of the previous data (+/-11 mils) and instrument accuracy of (+/-10 mils) for a total of 21 mils. Deviation from this value will be considered unexpected and requires corrective actions described below.

The applicant further stated in its response that if additional corrosion is identified that exceeds acceptance criteria described above, Oyster Creek will initiate corrective actions that include one or all of the following, depending on the extent of identified corrosion.

a. Perform additional UT measurements to confirm the readings

b. Notify NRC within 48 hours of confirmation of the identified condition

c. Conduct inspection of the coatings in the sand bed region in areas where the additional corrosion was detected.

d. Perform engineering evaluation to assess the extent of the condition and to determine if additional inspections are required to assure drywell integrity.

e. Perform operability determination and justification for continued operation until next scheduled inspection.

These actions will be completed before restarting from an outage.

The project team noted that the above commitments are included in Audit Commitment 3.0.3.2.22-5, which was discussed previously in this section.

Pitting Corrosion of the Suppression Chamber (Torus)

In reviewing information in the OCGS AMP B.1.27 discussion of operating experience for the suppression chamber (torus) and vent system, the project team noted that the applicant stated that the coating is inspected every outage and repaired, as required, to protect the torus shell and the vent system from corrosion. Reference is made to program B.1.33 for additional details. The project team reviewed OCGS AMP B.1.33 and noted that, under operating experience, the applicant stated that torus and vent header vapor space Service Level I coating inspections performed in 2002 found the coating in these areas to be in good condition. Inspection of the immersed coating in the torus identified blistering. The blistering occurred primarily in the shell invert, but was also noted on the upper shell near the water line. The majority of the blisters remained intact and continued to protect the base metal. However, several blistered areas included pitting damage where the blisters were fractured. A qualitative assessment of the identified pits was performed and concluded that the measured pit depths were significantly less than the established acceptance criteria. The fractured blisters were repaired to reestablish the protective coating barrier.

To clarify the above statements, in audit question AMP-072, the project team asked the applicant to provide the following information pertaining to past operating experience and license renewal aging management for the suppression chamber (torus) and vent system:

> (1) The plant documentation that describes the blistering and pitting, the qualitative assessment performed, the established acceptance criteria, and the corrective action taken,
>
> (2) Clarify whether ASME Section XI, Subsection IWE was applied to develop the acceptance criteria,
>
> (3) Clarify whether the inspection that discovered the blistering and cracking was conducted under IWE, a coatings monitoring and maintenance program, or another program. If another program, identify the program, and
>
> (4) Clarify whether both the IWE program (B.1.27) and the coatings program (B.1.33) are credited to manage loss of material due to corrosion for the suppression chamber (torus) and vent system, for the extended period of operation. If not, provide the technical basis for concluding that both AMPs do not need to be credited.

In its response, the applicant stated that inspection of the suppression chamber (torus) and vent system coating is conducted by divers every other outage in accordance with engineering specification SP-1302-52-120. The specification provides inspection and acceptance criteria for the coating. It also provides inspection and acceptance criteria for pitting, as a contingency to be used in the event failure of the coating results in pitting. The coating is monitored for cracks, sags, runs, flaking, blisters, bubbles, and other defects described in the Protective Coating Monitoring and Maintenance Program (B.1.33).

The applicant further stated that the specification requires inspection of the torus and vent system surfaces for coating integrity. If pitting is observed, then isolated pits of 0.125" in diameter have an allowed maximum depth of 0.261" anywhere in the shell, provided the center-to-center distance between the subject pits and neighboring isolated pits or areas of pitting corrosion is greater that 20 inches. Multiple pits that can be encompassed by a 2.5-inch diameter circle are limited to a maximum depth of 0.141 inches provided the center-to-center distance between the subject pitted area and neighboring isolated pits, or areas of pitting corrosion, is greater that 20 inches.

Plant documentation that describes the blistering and pitting, and qualitative assessment performed, the established acceptance criteria, and corrective actions taken, is included in PBD-AMP-B.1.27 Notebook and is available for staff review.

On April 19, 2006, the applicant supplemented its response to include the statement ?Pits greater that 0.040 inches in depth shall be documented and submitted to engineering for evaluation."

The applicant further stated in its response that the torus and vent system coating is classified Service Level I Coating as described in the Protective Coating Monitoring and Maintenance Program (B.1.33). The program was evaluated against the 10 elements of NUREG-1801 XI.S8, ?Protective Coating Monitoring and Maintenance Program"and found consistent without enhancements or exceptions. Acceptance criteria are evaluated in element 3.6 of the Oyster Creek Protective Coating Monitoring and Maintenance Program (PBD-AMP-B.1.33). The inspection is performed by ASME Section XI Level II and Level III inspectors. Acceptance criteria for pits are based on engineering analysis that uses the method of Code Case N-597 as guidance for calculation of pit depths that will not violate the local stress requirements of either ASME Section III, 1977 Edition or Section VIII, 1962 Edition.

On April 19, 2006, the applicant supplemented its response to include the statement ?In regard to the use of Code Case N-597 for the evaluation of pits, see AMP-210 for additional information." The applicant's response to audit question AMP-210 is discussed below in this section of the audit and review report.

The applicant also stated in its response that the inspection that discovered the blistering was conducted under the Protective Coating Monitoring and Maintenance Program. Examinations are performed by ASME Section XI Level II and Level III inspectors. The applicant further stated in its response that both the IWE program (B.1.27) and the coatings program (B.1.33) are credited to manage loss of material due to corrosion for the suppression chamber (torus) and the vent system for the extended period of operation.

On April 19, 2006, the applicant supplemented its response to clarify that during the period of extended operation, torus coating inspection will be performed in all 20 torus bays at a frequency of every other refueling outage for the current coating system. Should the coating system be replaced, the inspection frequency and scope will be re-evaluated. The inspection scope will, as a minimum, meet the requirements of ASME, Subsection IWE. This specific commitment will be added to the LRA Appendix A.5 Commitment List, as part of Commitment 33 associated with the Protective Coating Monitoring and Maintenance Program.

In its letter dated May 1, 2006 (AmerGen Letter No. 2130-06-20328), the applicant committed to the following: As noted in AmerGen's 4/4/06 letter to NRC, AmerGen will perform torus coating inspections in accordance with ASME Section XI, Subsection IWE every other refueling outage prior to and during the period of extended operation. This new commitment clarifies that the scope of each of these inspections will include the wetted area of all 20 torus bays. Should the current torus coating system be replaced, the inspection frequency and scope will be re-evaluated. Inspection scope will, as a minimum, meet the requirements of ASME Section XI, Subsection IWE. This is **Audit Commitment 3.0.3.2.22-7.**

On April 19, 2006, the applicant supplemented its response, stating that Condition Report No. 373695 Assignments 2 and 3 have been initiated to drive program improvements for the monitoring and trending of torus design margins, and to develop refined acceptance criteria and thresholds for entering coating defects and unacceptable pit depths into the Corrective Action process for further evaluation. These improvements will be incorporated into the inspection implementing documents prior to the next performance of these inspections, which is also prior to the period of extended operation. This commitment will be described in a letter to the NRC.

In its letter dated May 1, 2006 (AmerGen Letter No. 2130-06-20328), the applicant committed to the following: AmerGen will develop refined acceptance criteria and thresholds for entering torus coating defects and unacceptable pit depths into the corrective action process for further evaluation. These improvements will be incorporated into the inspection implementing documents prior to the next performance of these inspections, which is also prior to the period of extended operation. This is **Audit Commitment 3.0.3.2.22-8.**

The project team found the applicant’s commitment acceptable since it will provide additional criteria to determine whether degradation of the suppression chamber is being adequately managed.

On April 19, 2006, the applicant supplemented its response, stating that the answers provided for audit question AMP-210 on torus wall thickness were written to address specific concerns of the AMP audit team and were centered around worse case torus thickness margins existing on the torus shell due to corrosion. The applicant stated that this supplemental information is being provided to reinforce that, based on all available inspection results, the average thickness of the torus remains at 0.385". Based on the results of the inspections performed through 1993 (14R), the applicant concluded that the torus shell thickness had remained virtually unchanged following the repair and recoating efforts performed in 1984. The applicant also stated that this was communicated to the NRC via letter C321-94-2186 dated November 3, 1994, Amendment No. 177 to DPR-16 and SER dated February 21, 1995 for the EMRV Tech Spec change. Coating inspections performed subsequent to 1993 (14R) continue to confirm that the torus shell thickness has remained virtually unchanged following the repair and recoating efforts performed in 1984, and that the average thickness of the torus remains at 0.385". Torus integrity will continue to be evaluated during future inspections (performed every other refueling outage) into the period of extended operation.

The applicant also clarified the extent of pitting corrosion. Pitting corrosion less than or equal to 0.040" was not repaired during the 1984 torus repair and recoating effort based on available margins and was found to be acceptable without any size restriction since it satisfied minimum uniform thickness requirements. Inspection activities subsequent to 1984 have identified 5 isolated pits that exceed 0.040". The following areas have been mapped for trending and analysis during future inspections: 1 pit of 0.042" in bay 1; 1 pit of 0.0685" in bay 2; 2 pits of 0.050" in bay 6; 1 pit of 0.058" in bay 10. Shell thicknesses have been evaluated against code requirements and found to satisfy all design and licensing basis requirements. Therefore, the integrity of the torus shell has been verified to have adequate shell thickness margins to ensure design and licensing basis requirements can be maintained.

As noted above, the applicant also supplemented its response to include the statement ?Pits greater that 0.040 inches in depth shall be documented and submitted to engineering for evaluation.”

The project team noted that in the discussion of torus degradation on pages 25 to 31 of program basis document PBD-AMP-B.1.27, the applicant stated that "Inspections performed in 2002 found the coating to be in good condition in the vapor area of the torus and vent header, and in fair condition in immersion. Coating deficiencies in immersion include blistering, random and mechanical damage. Blistering occurs primarily in the shell invert but was also noted on the upper shell near the water line. The fractured blisters were repaired to reestablish the protective coating barrier. This is another example of objective evidence that the Oyster Creek ASME Section XI, Subsection IWE aging management program can identify degradation and implement corrective actions to prevent the loss of the containment's intended function. While blistering is considered a deficiency, it is significant only when it is fractured and exposes the base metal to corrosion attack. The majority of the blisters remain intact and continue to protect the base metal; consequently the corrosion rates are low. Qualitative assessment of the identified pits indicate that the measured pit depths (50 mils max) are significantly less than the criteria established in Specification SP-1302-52-120 (141- 261 mils, depending on diameter of the pit and spacing between pits)."

In audit question AMP-210, the project team asked the applicant to confirm or clarify (1) that only the fractured blisters found in this inspection were repaired; (2) pits were identified where the blisters were fractured; (3) pit depths were measured and found to 50 mils maximum; (4) the inspection Specification SP-1302-52-120 includes pit-depth acceptance criteria for rapid evaluation of observed pitting; (5) the minimum pit depth of concern is 141 mils (0.141") and pits as deep as 261 mils (0.261") may be acceptable.

In its response, the applicant stated that Specification SP-1302-52-120, ?Specification for Inspection and Localized Repair of the Torus and Vent System Coating," specifies repair requirements for coating defects exposing substrate and fractured blisters showing signs of corrosion. The repairs referred to in the inspection report included fractured blisters, as well as any mechanically damaged areas, which have exposed bare metal showing signs of corrosion. Therefore, only fractured blisters would be candidates for repair, not those blisters that remain intact. The number and location of repairs are tabulated in the final inspection report prepared by Underwater Construction Corporation.

The applicant further stated in its response that coating deficiencies in the immersion region included blistering with minor mechanical damage. Blistering occurred primarily in the shell invert but was also noted on the upper shell near the water line. The majority of the blisters were intact. Intact blisters were examined by removing the blister cap exposing the substrate. Corrosion attack under non-fractured blisters was minimal and was generally limited to surface discoloration. Examination of the substrate revealed slight discoloration and pitting with pit depths less than 0.001. Several blistered areas included pitting corrosion where the blisters were fractured. The substrate beneath fractured blisters generally exhibited a slightly heavier magnetite oxide layer and minor pitting (less than 0.010") of the substrate.

The applicant indicated that, in addition to blistering, random deficiencies that exposed base metal were identified in the torus immersion region coating (e.g., minor mechanical damage) during the 19R (2002) torus coating inspections. They ranged in size from 1/16" to ½" in diameter. Pitting in these areas was qualitatively evaluated and ranged from less than 10 mils to slightly more than 40 mils in a few isolated cases. Three quantitative pit depth measurements were taken in several locations in the immersion area of Bay 1. Pit depths at these sites ranged from 0.008" to 0.042" and were judged to be representative of typical conditions found on the shell. Prior to the 2002 inspection, 4 pits greater than 0.040" were identified. The pit depths were 0.058" (1 pit in 1988), 0.05" (2 pits in 1991), and 0.0685" (1 pit in 1992). The pits were evaluated against the local pit depth acceptance criteria and found to be acceptable.

The applicant further stated in its response that Specification SP-1302-52-120, ?Specification for Inspection and Localized Repair of the Torus and Vent System Coating," includes the pit-depth acceptance criteria for rapid evaluation of observed pitting. The acceptance criteria are supported by a calculation C-1302-187-E310-038. Locations that do not meet the pit-depth acceptance criteria are characterized based on the size of the area, center to center distance between corroded areas, the maximum pit depth and location in the torus based on major structural features. These details are sent to Oyster Creek Engineering for evaluation.

The applicant also stated that the acceptance criteria for pit depth is as follows: Isolated Pits of 0.125" in diameter have an allowed maximum depth of 0.261" anywhere in the shell provided the center-to-center distance between the subject pit and neighboring isolated pits or areas of pitting corrosion is greater than 20.0 inches. This includes old pits or old areas of pitting corrosion that have been filled and/or re-coated. Multiple pits that can be encompassed by a

2-1/2" diameter circle shall be limited to a maximum pit depth of 0.141" provided the center-to-center distance between the subject pitted area and neighboring isolated pits or areas of pitting corrosion is greater than 20.0 inches. This includes old pits or old areas of pitting corrosion that have been filled and/or re-coated.

In audit question AMP-210, the project team asked the applicant to provide the following information for the torus: (1) nominal design, as-built, and minimum measured thickness of the torus; (2) minimum thickness required to meet ASME code acceptance criteria; and (3) the technical basis for the pitting acceptance criteria included in Specification SP-1302-52-120.

In its response, the applicant stated the following: For the submersed area of the drywell (torus), the nominal design thickness is 0.385 inches, and the as-built thickness is 0.385 inches. The minimum uniform measured thickness is 0.343 inches for the general shell, 0.345 inches for the shell ring girders, 0.345 inches for the shell saddle flange, and 0.345 inches for the shell torus straps. The minimum general thickness required to meet ASME Code Acceptance is 0.337 inches.

The applicant further stated in its response that the technical basis for pitting acceptance criteria included in Specification SP-1302-52-120 is based on engineering calculation C-1302-187-E310-038. At the time of preparation of calculation C-1302-187-E310-038 in 2002, there were no published methods to calculate acceptance standards for locally thinned areas in ASME Section III or Section VIII Pressure Vessel codes. Therefore, the approach in Code Case N-597 was used as guidance in assessing locally thinned areas in the torus. This is based on the similarity in approaches between Local Thinning Areas described in N-597 and Local Primary Stress areas described in Paragraph NE3213.10 of the ASME Code Section III, particularly small areas of wall thinning which do not exceed 1.0 x (square root of Rt). In addition, the ASME Code Section III, Subsection NB, Paragraph NB-3630 allows the analysis of pipe systems in accordance with the Vessel Analysis rules described in Paragraph NB-3200 of the same Subsection as an alternate analysis approach. Therefore, the approach used in N-597 for local areas of thinning was probably developed using the rules for Local Primary Membrane Stress from paragraph NB-3200, in particular Subparagraph 3213.10. The Local Primary Stress Limits in NB- 3213.10 are similar to those discussed in Subsection NE, Paragraph NE-3213.10.

Since the Code Case had not yet been invoked into the Section XI program, the calculation provided a reconciliation of the results obtained from the code case against the ASME Section III code requirements, as discussed above. This reconciliation demonstrated that the approach in Code Case N-597 used on a pressure vessel such as the torus would be acceptable since the results are conservative compared to the previous work performed in MPR-953, "GPU Nuclear Corporation, Oyster Creek Nuclear Generating Station Torus Shell Thickness Margin", MPR Associates INC, October 1986.

The applicant further stated that currently, the maximum pit depth measured in the torus is 0.0685" (measured in 1992 in bay 2). The applicant found it acceptable based on the design calculations existing at that time and was not based on Calculation C-1302-187-E310-038. This remains the bounding wall thickness in the torus. The criterion developed in 2002 for local thickness acceptance provides an easier method for evaluating as-found pits. The results were shown to be conservative versus the original ASME Section III and VIII Code requirements for the torus. The torus inspection program is being enhanced per IR 373695 (audit commitment 3.0.3.2.22-8) to improve the detail of the acceptance criteria and margin management requirements using the ASME Section III criteria. The approach used in C-1302-187-E310-038 will be clarified as to how it maintains the code requirements. If Code Case N-597-1 is required to develop these criteria for future inspections, NRC review and approval will be obtained. It should also be noted that the program has established corrosion rate criteria and the applicant continues to periodically monitor the criteria to verify they remain bounded.

Containment Degradation Commitments

The project team evaluated the applicant's revised aging management commitments to address four (4) distinct issues: monitoring/eliminating water leakage; corrosion in the upper drywell region; corrosion in the former sand bed region; and pitting corrosion in the suppression chamber (torus). Each area is discussed in the following paragraphs.

1. Monitoring/Eliminating Water Leakage in the Gap Between the Drywell and Shield Wall

The applicant made a new license renewal commitment (3.0.3.2.22-1), to continue the use of the strippable coating for each refueling during the license renewal period. According to the applicant, this coating has been effective in eliminating water intrusion into the annular space between the drywell shell and the concrete shield wall. In the LRA, the applicant had not committed to continue its use.

The applicant also made a new license renewal commitment (3.0.3.2.22-2) to investigate the source of leakage, take corrective actions, evaluate the impact of the leakage and, if necessary, perform additional drywell inspections in the event water leakage from the former sand bed region is found during the period of extended operation. Under the current license term, Oyster Creek is committed to NRC to monitor the former sand bed region drains for water leakage. This commitment was not previously identified in the LRA.

In its response to audit question AMP-205, the applicant indicated that there is no formal procedure in place to monitor leakage from the sand bed drains, and stated ?Issue Report #348545 was submitted into the corrective action program when this was discovered. Corrective actions have been initiated to create recurring activities controlled with the work management process and procedures, to perform all future required inspections to meet the present commitment."

The project team found that the absence of a leakage monitoring program to meet the current license term commitment raises a question about the basis for the applicant's claim that water is no longer leaking into the annular gap between the drywell shell and the concrete shield wall. The project team identified the review of applicant information that confirms absence of water leakage into the annular gap between the drywell shell and the concrete shield wall as **Open Item 3.0.3.2.22-1.**

2. Upper Drywell Region

The applicant made a new license renewal commitment (3.0.3.2.22-3), to continue performing UT measurements of the upper drywell region for the period of extended operation.

The project team noted that the applicant manages loss of material due to corrosion in the upper drywell region (spherical and cylindrical sections) using augmented examinations in accordance with IWE-1240. An Ultrasonic thickness survey is performed every other refueling outage (4 years) to detect any additional loss of material due to corrosion. The UT results are evaluated and trended to ensure that the drywell shell is capable of performing its intended function to the end of plant life. The areas subject to periodic UT measurements were selected based on extensive exploratory testing to establish the most severely corroded locations in the drywell above the sand bed region. Corrosion of the upper drywell region is a TLAA, in accordance with 10 CFR 54.21(c). The applicant's TLAA is documented in LRA Section 4.7.2. The applicant is implementing TLAA option (iii), and uses the UT inspection results from its IWE program to monitor remaining thickness; to periodically update the corrosion rate, and to periodically update the projected remaining thickness at the end of the license renewal period.

The project team did not review the applicant's TLAA. The NRR/DE staff has responsibility for this TLAA, and submitted formal RAIs to the applicant. The project team coordinated its efforts with NRR/DE to avoid duplication.

3. Former Sand Bed Region of Drywell

In the LRA, the applicant's position was that corrosion in the former sand bed region has been completely arrested by the remedial actions already taken. The original LRA commitment was to inspect a section of coating every other outage (4 yrs) to confirm its soundness. The last UT readings were taken in 1996. As a result of the audit, the applicant made several new commitments to manage aging of the former sand bed region of the drywell during the period of extended operation. The applicant's revised commitments are as follows:

(1) Monitor the protective coating on the exterior surfaces of the drywell in the sand bed region in accordance with the requirements of ASME Section XI, Subsection IWE during the period of extended operation (commitment 3.0.3.2.22-4),

(2) Conduct periodic UT inspection of the former sand bed region before entering the license renewal period, and every ten years thereafter (commitment 3.0.3.2.22-5),

(3) Attempt a UT inspection of some of the locally thinned areas identified in the 1992 inspection from the exterior of the drywell, during the initial UT inspections of the sand bed region conducted prior to entering the period of extended operation (commitment 3.0.3.2.22-6),

(4) Inspect the remaining 50% of the external coating in the former sand bed region before entering the license renewal period (to date, only 50% of this coating has been inspected since it was applied in the early 1990s), and conduct a 100% re-inspection of the coating every 10 years during the license renewal period (commitment 3.0.3.2.22-4),

(5) If additional corrosion of the sand bed region is identified by the UT inspection to be conducted before entering the license renewal period, initiate corrective actions that include one or all of the following, depending on the extent of identified corrosion:

- a. Perform additional UT measurements to confirm the readings.
- b. Notify NRC within 48 hours of confirmation of the identified condition.
- c. Conduct inspection of the coatings in the sand bed region in areas where the additional corrosion was detected.
- d. Perform engineering evaluation to assess the extent of the condition and to determine if additional inspections are required to assure drywell integrity.
- e. Perform operability determination and justification for continued operation until next scheduled inspection.

These actions will be completed before restarting from an outage (commitment 3.0.3.2.22-5).

The project team noted these new commitments for managing aging of the former sand bed region, but also noted the very small remaining margin between the minimum reported uniform thickness and the minimum required uniform thickness (0.800" vs. 0.736"). This apparent lack of margin led the project team to ask the applicant for additional information about (1) the UT inspection results and data reduction methods employed to determine the minimum remaining thickness, and (2) the analytical methodology employed to determine the minimum required thickness, specifically for localized areas where the measured thickness is less than the minimum required uniform thickness. The applicant provided additional information on these subjects in its responses to audit questions AMP-356 and AMP-210, respectively. During a follow-up onsite audit conducted April 19-20, 2006, the project team discussed these responses with the applicant in detail, to ensure a complete understanding.

The project team reviewed the detailed UT thickness readings in the sand bed region taken from the inside surface through 1996 and on the outside surface in 1992. The project team pointed out a definite bias in the 1996 readings, because the average thickness (based on 49 readings/location) increased at almost all locations. The project team and the applicant's staff discussed possible causes for this bias, but no conclusions could be drawn.

The project team's review of the UT data confirmed that the remaining thickness in the former sand bed region significantly exceeds the minimum required thickness of 0.736" at most monitored locations. Several locations are close to the original design thickness of 1.154". However, in a few very localized areas, primarily in Bay 1 and Bay 13, remaining thicknesses less than 0.736" have been measured. The lowest measured point reading is 0.618", recorded in the 1992 outside surface inspection. Based on project team's review of the data, the lowest measured point reading from the inside surface inspections is 0.646".

The project team also reviewed the technical basis documents that established compliance with ASME Code requirements. In its response to audit question AMP-210, the applicant stated that the engineering analysis that demonstrated compliance to ASME code requirements was performed in two parts, stress and stability analysis with sand, and stress and stability analyses without sand. The analyses are documented in GE Reports Index No. 9-1, 9-2, 9-3, and 9-4, which were transmitted to the NRC in December 1990 and in 1991, respectively. Index No. 9-3 and 9-4 were revised later to correct errors identified during an internal audit, and were resubmitted to the staff in January 1992.

The applicant stated that the drywell shell thickness in the sand bed region is based on stability analysis without sand (GE Report 9-4). The analysis is based on a 36-degree section model that takes advantage of symmetry of the drywell with 10 vents. The model includes the drywell shell from the base of the sand bed region to the top of elliptical head and the vent and vent header. The torus is not included in this model because the bellows provide a very flexible connection, which does not allow significant structural interaction between the drywell and the torus. The analysis assumed that the shell thickness in the entire sand bed region has been reduced uniformly to a thickness of 0.736 inches.

The applicant further indicated that GE Letter Report ?Sand Bed Local Thinning and Raising the Fixity Height Analysis" presents results demonstrating that a uniform reduction in thickness of 27% to 0.536" over a one square foot area would only create a 9.5% reduction in the load factor and theoretical buckling stress for the whole drywell. A second buckling analysis was performed for a wall thickness reduction of 13.5% to 0.636" over a one square foot area, which only reduced the load factor and theoretical buckling stress by 3.5% for the whole drywell. To bring these results into perspective, the applicant's review of the NDE reports indicate there are

20 UT measured areas in the whole sand bed region that have thicknesses less than the 0.736 inch thickness used in GE Report 9-4, which cover a total area of 0.68 square feet of the drywell surface with an average thickness of 0.703" or a 4.5% reduction in wall thickness. Furthermore, all of these very local wall areas are centered about the vents, which significantly stiffen the shell. This stiffening effect limits the shell buckling to a point in the shell sand bed region, which is located at the midpoint between two vents.

Based on its review of the detailed UT thickness readings and the GE stability analyses that considered (1) a uniform 0.736" thick sand bed region, and (2) the effects of a local thin area of 0.536" and 0.636" thickness, the NRC concluded in 1996 that the condition of the former sand bed region was adequate to perform its intended function in accordance with its design basis.

However, because there has been no UT inspection conducted since 1996 and the remaining corrosion margin in 1996 was less than 0.1" at several locations, the project team initiated further evaluation of the applicant's aging management commitment for UT inspection of the former sand bed region. The project team identified the review of applicant information that confirms the drywell shell in the former sand bed region has the minimum required thickness to ensure no loss of intended function during the extended period of operation as **Open Item 3.0.3.2.22-2.**

The applicant credited its Protective Coating Monitoring and Maintenance Program (OCGS AMP B.1.33) to monitor/maintain the protective coating on the exterior surface of the drywell in the former sand bed region. The project team evaluated OCGS AMP B.1.33 in Section 3.0.3.1.8 of this audit and review report. The applicant's revised aging management commitment (3.0.3.2.22-4) is to complete a 100% inspection of the coating (initiated in 1994 and currently 50% complete) prior to the license renewal period, and to conduct subsequent 100% re-inspections every 10 years during the license renewal period.

Because of the minimal corrosion margin remaining in the former sand bed region, and the applicant's reliance on the coating to mitigate additional corrosion, the project team initiated further review of the applicant's inspection program to ensure that the coating will continue to perform its intended function for the extended period of operation. The project team identified the review of applicant information that confirms the drywell shell in the former sand bed region has the minimum required thickness and that coating and inspections are adequate to ensure no loss of intended function during the extended period of operation as **Open Item 3.0.3.2.22-3.**

4. Suppression Chamber (Torus)

The applicant credited its Protective Coating Monitoring and Maintenance Program (OCGS AMP B.1.33) to monitor/maintain the protective coatings inside the suppression chamber (torus), in order to mitigate corrosion. The project team's detailed evaluation of the applicant's Protective Coating Monitoring and Maintenance Program (OCGS AMP B.1.33) is in Section 3.0.3.1.8 of this audit report.

The project team questioned the applicability and implementation of Code Case N-597-1 for developing pit depth acceptance criteria for the torus. Based on the acceptance criteria developed by the applicant, an isolated pit of 0.125" diameter on the inner surface is considered acceptable if its depth does not exceed 0.261". According to the applicant, the torus as-built wall thickness is 0.385". Therefore, a pit depth equal to 67% of the as-built thickness is considered acceptable, if it is isolated. For a cluster of pits within a 2.5" diameter circle, the acceptable pit depth is 0.141" or 37% of the as-built thickness. The acceptable pit depth includes allowance for an assumed 0.0009"/yr corrosion rate over the 4 year period between inspections. The project team also identified that RG 1.147 stipulates the following condition on the use of Code Case N-597-1: "(5) For corrosion phenomena other than flow-accelerated corrosion, use of the Code Case is subject to NRC review and approval. Inspection plans and wall thinning rates may be difficult to justify for certain degradation mechanisms such as MIC and pitting."

In its response to audit question AMP-210, the applicant stated that currently, the maximum pit depth measured in the torus is 0.0685" (measured in 1992 in bay 2). The applicant evaluated this as acceptable using the design calculations existing at that time and was not based on Calculation C-1302-187-E310-038. This remains the bounding wall thickness in the torus. The criterion developed in 2002 for local thickness acceptance provides an easier method for evaluating as-found pits. The results were shown to be conservative versus the original ASME Section III and VIII Code requirements for the torus. The applicant stated that the torus inspection program is being enhanced per IR 373695 [this is audit commitment 3.0.3.2.22-8] to improve the detail of the acceptance criteria and margin management requirements using the ASME Section III criteria. The approach used in C-1302-187-E310-038 will be clarified as to how it maintains the code requirements. If Code Case N-597-1 is required to develop these criteria for future inspections, NRC review and approval will be obtained. It should also be noted that the program has established corrosion rate criteria and continues to periodically monitor to verify they remain bounded.

The applicant's response clarified for the project team that pit depth acceptance criteria based on Code Case N-597-1 had not been implemented to date, and if implementation should be contemplated, the applicant will seek NRC review and approval. The project team found this acceptable to resolve its concern about the use of Code Case N-597-1.

Based on the applicant's response to audit question AMP-210, it appeared to the project team that there was minimal margin remaining between the current remaining thickness and the minimum required thickness for the torus. During a follow-up onsite audit conducted April 19-20, 2006, the project team discussed with the applicant the current condition of the torus, the pit depth acceptance criteria, and the scope of the coating inspection conducted every 4 years.

The applicant explained that the average remaining thickness of the torus is essentially the as-built thickness (0.385"). Five (5) isolated pits, ranging from 0.042" to 0.068" in depth, are monitored and trended during each inspection. The applicant supplemented its earlier response to audit question AMP-072, to document this.

The applicant further explained that pit depth acceptance criteria based on Code Case N-597-1 had never been used to disposition the acceptability of observed pitting. The current practice is to record and monitor all pits exceeding 0.040 inches in depth. The applicant supplemented its earlier response to audit question AMP-072 to indicate that ?Pits greater than 0.040 inches in depth shall be documented and submitted to engineering for evaluation."

The applicant supplemented its earlier response to audit question AMP-072, committing to inspect the coating in all 20 bays of the suppression chamber (torus) during the period of extended operation. The frequency of inspection will be every other refueling outage for the current coating system. Should the coating system be replaced, the inspection frequency and scope will be re-evaluated. The inspection scope will, as a minimum, meet the requirements of ASME, Subsection IWE (audit commitment 3.0.3.2.22-7).

The applicant supplemented its earlier response to audit question AMP-072, committing to improve the monitoring and trending of torus design margins, and to develop refined acceptance criteria and thresholds for entering coating defects and unacceptable pit depths into the Corrective Action process for further evaluation. These improvements will be incorporated into the inspection implementing documents prior to the next performance of these inspections, which is also prior to the period of extended operation (audit commitment 3.0.3.2.22-8).

Based on the project team's understanding of (1) the current condition of the torus, (2) the applicant's plan to refine the pit depth acceptance criteria, and (3) the scope of the coating inspection conducted every 4 years, the project team determined that the applicant's aging management program for the suppression chamber (torus) ensures that the effects of aging will be adequately managed during the extended period of operation.

The project team reviewed those portions of the ASME Section XI, Subsection IWE program for which the applicant claims consistency with GALL AMP XI.S1"ASME Section XI, Subsection IWE," with an exception as described below and based on that review, initiated the open items pertaining to the aging management of primary containment (drywell shell) discussed above.

3.0.3.2.22.3 Exceptions to the GALL Report

In the OCGS LRA, the applicant stated the following exception to the GALL Report program elements:

Element: Program Description

Exception: NUREG-1801 evaluation is based on ASME Section XI, 2001 Edition including 2002 and 2003 Addenda. The current Oyster Creek ASME Section XI, Subsection IWE program plan for the First Ten-Year inspection interval effective from September 9, 1998 through September 9, 2008, approved per 10CFR50.55a, is based on ASME Section XI, 1992 Edition including 1992 addenda. The next 120-month inspection interval for Oyster Creek will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a 12 months before the start of the inspection interval.

The GALL Report identified the following recommendations for the ?program description" program element associated with the exception taken:

Program Description: 10 CFR 50.55a imposes the inservice inspection (ISI) requirements of the ASME Code, Section XI, Subsection IWE for steel containments (Class MC) and steel liners for concrete containments (Class CC). The full scope of IWE includes steel containment shells and their integral attachments; steel liners for concrete containments and their integral attachments; containment hatches and airlocks; seals, gaskets and moisture barriers; and pressure-retaining bolting. This evaluation covers the 2001 edition1 including the 2002 and 2003 Addenda, as approved in 10 CFR 50.55a. ASME Code Section XI, Subsection IWE and the additional requirements specified in 10 CFR 50.55a(b)(2) constitute an existing mandated program applicable to managing aging of steel containments, steel liners of concrete containments, and other containment components for license renewal.

The project team noted that the 1992 ASME Code, Section XI, Subsection IWE, including 1992 addenda, was incorporated into 10 CFR 50.55a at the time the applicant was required to declare its inspection basis for the current 10-year IWE inspection interval. The applicant will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a twelve months before the start of the next 120-month inspection interval. Since this is consistent with the recommendations in the GALL Report, the project team does not consider this to be an actual exception to GALL. On this basis, the project team found this exception acceptable.

3.0.3.2.22.4 Enhancements

None.

3.0.3.2.22.5 Operating Experience

The applicant stated, in the OCGS LRA, that ASME Section XI, Subsection IWE as described in Oyster Creek First-10 Year Containment (IWE) Inservice Inspection Program Plan and Basis is effective September 9, 1998 to September 9, 2008. Base line inspection of containment surfaces was completed in 2000 and a second inspection was completed in 2004. The 2004 inspection identified (2) recordable conditions, a loose locknut was identified on a spare drywell penetration and a weld rod was found stuck to the underside of the drywell head. Engineering evaluation concluded the stuck weld rod has no adverse impact on drywell head structural integrity and the loose locknut did not affect the seal of the containment penetration.

The applicant stated that the upper region of drywell shell has experienced loss of material, due to corrosion, as a result of water leakage into the gap between the containment and the reactor building in the 1980’s. As a result the area is subject to augmented examinations as required by ASME Section XI, Subsection IWE. The examination is by ultrasonic (UT) thickness measurements. UT measurements taken in 2004 showed that the drywell shell thickness meets ASME criteria and that the rate of corrosion is in a declining trend. The applicant’s engineering evaluation of the UT results also concluded that the containment drywell, considering the current corrosion rate, is capable of performing its intended function through the period of extended operation. Further discussion is provided in LRA Section 4.7.2, ?Drywell Corrosion” TLAA evaluation.

The applicant also stated that the sand bed region also experienced loss of material due to corrosion. Corrosion was attributed to the presence of oxygenated wet sand and exacerbated by the presence of chloride and sulfate in the sand bed region. As a corrective measure, the sand was removed and a protective coating was applied to the shell to mitigate further corrosion. The applicant stated that subsequent inspections confirmed that corrosion of the shell has been arrested. The coating is monitored periodically under the Protective Coating Monitoring and Maintenance Program, B.1.33. Refer to program B.1.33 for additional details.

The applicant also stated that the suppression chamber (torus) and vent system were originally coated with Carboline Carbo-Zinc 11 paint. The coating is inspected every outage and repaired, as required, to protect the torus shell and the vent system from corrosion. Refer to program B.1.33 for additional details.

The applicant stated that the operating experience review concluded that ASME Section XI, Subsection IWE is effective for managing aging effects of primary containment surfaces.

In OCGS PBD-AMP-B.1.27, the applicant expanded its discussion of operating experience to include industry operating experience and additional details of the plant-specific containment degradation. The applicant stated that a review of industry operating experience has confirmed that corrosion has occurred in containment shells. NRC INs 86-99, 88-82 and 89-79 described occurrences of corrosion in steel containment shells. NRC GL 87-05 addressed the potential for corrosion of boiling water reactor (BWR) Mark I steel drywells in the "sand pocket region." More recently, NRC IN 97-10 identified specific locations where concrete containments are susceptible to liner plate corrosion. A review of plant operating experience at Oyster Creek shows that corrosion has occurred in several containment locations. These locations include the drywell shell in the sand bed region, the drywell shell above the sand bed region, and the suppression chamber and vent system. In all cases after being implemented, the Oyster Creek ASME Section XI, Subsection IWE aging management program has identified and corrected the degradation. The experience with the Oyster Creek ASME Section XI, Subsection IWE aging management program shows that the Oyster Creek ASME Section XI, Subsection IWE aging management program is effective in managing aging affects for the primary containment and its components.

The applicant included the following discussion and three examples of operating experience to provide evidence that the Oyster Creek ASME Section XI, Subsection IWE aging management program is effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

Discussion:

The Oyster Creek ASME Section XI, Subsection IWE aging management program as described in Oyster Creek 10 Year Containment (IWE) Inservice Inspection Program Plan and Basis is in effect from September 9,1998 to September 9, 2008. Base line inspection of the drywell was completed during 2000, refueling outage. The suppression chamber (torus) vapor region base line inspection was completed during 2000, refueling outage.

Although the Oyster Creek ASME Section XI, Subsection IWE aging management program implementation is recent, the potential for loss of material, due to corrosion, in inaccessible areas of the containment drywell shell was first recognized in 1980 when water was discovered coming from the sand bed region drains. Corrosion was later confirmed by ultrasonic thickness (UT) measurements taken during the 1986 refueling outage. As a result, several corrective actions were initiated to determine the extent of corrosion, evaluate the integrity of the drywell, mitigate accelerated corrosion, and monitor the condition of containment surfaces. The corrective actions include extensive UT measurements of the drywell shell thickness, removal of the sand in the sand bed region, cleaning and coating exterior surfaces in areas where sand was removed, and an engineering evaluation to confirm the drywell structural integrity. A corrosion monitoring program was established, in 1987, for the drywell shell above the sand bed region to ensure that the containment vessel is capable of performing its intended functions. Elements of the program have been incorporated into the ASME Section XI, Subsection IWE and provide for (1) periodic UT inspections of the shell thickness at critical locations, (2) calculations which establish conservative corrosion rates, (3) projections of the shell thickness based on the conservative corrosion rates, and (4) demonstration that the minimum required shell thickness is in accordance with ASME code.

Additionally, the NRC was notified of this potential generic issue that later became the subject of NRC IN 86-99 and GL 87-05. A summary of the operating experience, monitoring activities, and corrective actions taken to ensure that the primary containment will perform its intended functions is discussed below.

Examples of Operating Experience:

1. Drywell Shell in the Sand Bed Region:

The drywell shell is fabricated from ASTM A-212-61T Gr. B steel plate. The shell was coated on the inside surface with an inorganic zinc (Carboline carbozinc 11) and on the outside surface with "Red Lead" primer identified as TT-P-86C Type I. The red lead coating covered the entire exterior of the vessel from elevation 8' 11.25" (Fill slab level) to elevation 94' (below drywell flange). The sand bed region was filled with dry sand as specified by ASTM 633. Leakage of water from the sand bed drains was observed during the 1980 and 1983 refueling outages. A series of investigations were performed to identify the source of the water and its leak path. The results concluded that the source of water was from the reactor cavity, which is flooded during refueling outages. As a result of the presence of water in the sand bed region, extensive UT thickness measurements (about 1000) of the drywell shell were taken to determine if degradation was occurring. These measurements corresponded to known water leaks and indicated that wall thinning had occurred in this region.

Because of reduced thickness readings, additional thickness measurements were obtained to determine the vertical profile of the thinning. A trench was excavated inside the drywell, in the concrete floor, in the area where thinning at the floor level was most severe. Measurements taken from the excavated trench indicated that thinning of the embedded shell in concrete were no more severe than those taken at the floor level and became less severe at the lower portions of the sand bed region. Conversely, measurements taken in areas where thinning was not identified at the floor level showed no indication of significant thinning in the embedded shell. Aside from UT thickness measurements performed by plant staff, independent analysis was performed by the EPRI NDE Center and the GE Ultra Image III "C" scan topographical mapping system. The independent tests confirmed the UT results. The GE Ultra Image results were used as baseline profile to track continued corrosion.

To validate UT measurements and characterize the form of damage and its cause (i.e., due to the presence of contaminants, microbiological species, or both) core samples of the drywell shell were obtained at seven locations. The core samples validated the UT measurements and confirmed that the corrosion of the drywell is due to the presence of oxygenated wet sand and exacerbated by the presence of chloride and sulfate in the sand bed region. A contaminate concentrating mechanism due to alternate wetting and drying of the sand may have also contributed to the corrosion phenomenon. It was therefore concluded that the optimum method for mitigating the corrosion is by (1) removal of the sand to break up the galvanic cell, (2) removal of the corrosion product from the shell and (3) application of a protective coating.

Removal of sand was initiated during 1988 by removing sheet metal from around the vent headers to provide access to the sand bed from the Torus room. During operating cycle 13 some sand was removed and access holes were cut into the sand bed region through the shield wall. The work was finished in December 1992. After sand removal, the concrete surface below the sand was found to be unfinished with improper provisions for water drainage. Corrective actions taken in this region during 1992 included; (1) cleaning of loose rust from the drywell shell, followed by application of epoxy coating and (2) removing the loose debris from the concrete floor followed by rebuilding and reshaping the floor with epoxy to allow drainage of any water that may leak into the region. UT measurements taken from the outside after cleaning verified loss of material projections that had been made based on measurements taken from the inside of the drywell. There were, however, some areas thinner than projected; but in all cases engineering analysis determined that the drywell shell thickness satisfied ASME code requirements.

The Protective Coating Monitoring and Maintenance Program was revised to include monitoring of the coatings of exterior surfaces of the drywell in the sand bed region. The coated surfaces of the former sand bed region were subsequently inspected during refueling outages of 1994, 1996, 2000, and 2004. The inspections showed no coating failure or signs of deterioration. The applicant has stated that the inspections provide objective evidence that the coating is in a good condition and will provide adequate protection to the drywell shell in the sand bed region. Likewise, the applicant's evaluation of UT measurements taken from inside the drywell, in the in the former sand bed region, in 1992, 1994, and 1996, was the basis for the applicant to confirm that corrosion is mitigated. Therefore, the applicant concluded that corrosion in the sand bed region has been arrested and no further loss of material is expected. The applicant also concluded that monitoring of the coating in accordance with the Protective Coating Monitoring and Maintenance Program, will continue to ensure that the containment drywell shell maintains its intended function during the period of extended operation.

2. Drywell Shell above Sand Bed Region:

The UT investigation phase (1986 through 1991) also identified loss of material, due to corrosion, in the upper regions of the drywell shell. These regions were handled separately from the sand bed region because of the significant difference in corrosion rate and physical difference in design. Corrective action for these regions involved providing a corrosion allowance by demonstrating, through analysis, that the original drywell design pressure was conservative. Amendment 165 to the Oyster Creek Technical Specifications reduced the drywell design pressure from 62 psig to 44 psig. The new design pressure coupled with measures to prevent water intrusion into the gap between the drywell shell and the concrete allowed the upper portion of the drywell to meet ASME code requirements.

Originally, the knowledge of the extent of corrosion was based on UT measurements going completely around the inside of the drywell at several elevations. At each elevation, a belt-line sweep was used with readings taken on as little as 1" centers wherever thickness changed between successive nominal 6" centers. Six-by-six grids that exhibited the worst metal loss around each elevation were established using this approach and included in the Drywell Corrosion Inspection Program.

As experience increased with each data collection campaign, only grids showing evidence of a change were retained in the inspection program. Additional assurance regarding the adequacy of this inspection plan was obtained by a completely randomized inspection, involving 49 grids that showed that all inspection locations satisfied ASME code requirements. Evaluation of UT measurements taken through

2000 led the applicant to conclude the following: that corrosion is no longer occurring at two (2) elevations, and the 3rd elevation is undergoing a corrosion rate of 0.6 mils/year, while the 4th elevations is subject to 1.2 mils/year. The recent UT measurements (2004) confirmed that the corrosion rate continues to decline. The two elevations that previously exhibited no increase in corrosion continue the no corrosion increase trend. The rate of corrosion for the 3rd elevation decreased from 0.6 mils/year to 0.4 mils/year. The rate of corrosion for the 4th elevation decreased from 1.2 mils/year to 0.75 mils/year. After each UT examination campaign, an engineering analysis is performed by the applicant to ensure the required minimum thickness is provided through the period of extended operation. Thus corrosion of the drywell shell is considered a TLAA further described in Section 4.7.2.

3. Suppression Chamber (Torus) and Vent System

The Oyster Creek suppression chamber (torus) and vent system were originally coated with Carboline Carbo-Zinc 11 paint. The coating is inspected periodically and repaired to protect the Torus shell and the vent system in accordance with specification SP-1302-52-120. As a result wall thinning of the torus shell and the vent system has not been an issue. A review of past inspections of the torus shell and the vent system indicates the majority of the problems found have been attributed to blistering of coating in small areas, localized pitting. In 1983, pitted surfaces of the immersed torus shell were repair by welding. The torus shell, the interior of downcomers, and the entire interior surfaces of the vent system were recoated with Mobil 78-Hi Build Epoxy.

Inspection performed in 2002 found the coating to be in good condition in the vapor area of the torus and vent header, and in fair condition in immersion. Coating deficiencies in immersion include blistering, random and mechanical damage. Blistering occurs primarily in the shell invert but was also noted on the upper shell near the water line. The fractured blisters were repaired to reestablish the protective coating barrier. This is another example of objective evidence that the Oyster Creek ASME Section XI, Subsection IWE aging management program can identify degradation and implement corrective actions to prevent the loss of the containment's intended function.

While blistering is considered a deficiency, it is significant only when it is fractured and exposes the base metal to corrosion attack. The majority of the blisters remain intact and continues to protect the base metal; consequently the corrosion rates are low. Qualitative assessment of the identified pits indicate that the measured pit depths (50 mils max) are significantly less than the criteria established in Specification SP-1302-52-120 (141- 261 mils, depending on diameter of the pit and spacing between pits).

In OCGS PBD-AMP-B.1.27, the applicant concluded that the operating experience of the Oyster Creek ASME Section XI, Subsection IWE aging management program did not show any adverse trend in performance. Problems identified would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. The implementation of the Oyster Creek ASME Section XI, Subsection IWE aging management program will effectively identify containment aging effects prior to the loss of the containment function. Appropriate guidance for evaluation, repair, or replacement is provided for locations susceptible to degradation. Periodic self-assessments of the Oyster Creek ASME Section XI, Subsection IWE aging management program are performed to identify the areas that need improvement to maintain the quality performance of the program.

The project team reviewed the operating experience provided in the LRA and the B.1.27 program basis document, and also interviewed the applicant's technical staff. The project team determined that the OCGS plant-specific operating experience is unique, and is not bounded by industry experience. As discussed above, in Section 3.0.3.2.22.2 of this audit report, the project team's review of operating experience led to questions about the applicant's aging management commitments for the degraded containment, and resulted in three audit open items.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team identified three audit open items regarding the applicant's ASME Section XI, Subsection IWE program, to assess whether the program will adequately manage the aging effects that are identified in the OCGS LRA and PBD-AMP-B.1.27, for which this AMP is credited.

3.0.3.2.22.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the ASME Section XI, Subsection IWE program in OCGS LRA, Appendix A, Section A.1.27, which states that the ASME Section XI, Subsection IWE program is an existing program based on ASME Code and complies with the provisions of 10 CFR 50.55a. The program consists of periodic inspection of primary containment surfaces and components, including integral attachments, and containment vacuum breakers system piping and components for loss of material, loss of sealing, and loss of preload. Examination methods include visual and volumetric testing as required by the Code. Observed conditions that have the potential for impacting an intended function are evaluated for acceptability in accordance with ASME requirements or corrected in accordance with corrective action process. Procurement controls and installation practices, defined in plant procedures, ensure that only approved lubricants and tension or torque are applied to bolting.

In its letter dated April 4, 2006 (ML060970288), the applicant committed to the following:

- The OCGS LRA will be revised to credit the application of a strippable coating prior to flooding the drywell cavity for refueling during the period of extended operation. This is audit commitment 3.0.3.2.22-1.

- The OCGS LRA will be revised to credit investigation of the source of leakage, take corrective actions, evaluate the impact of the leakage and, if necessary, perform additional drywell inspections in the event water leakage from the former sand bed region is found during the period of extended operation. This is audit commitment 3.0.3.2.22-2.

- The OCGS LRA will be revised to note continued UT inspection of the drywell upper region during the period of extended operation. This is new commitment 3.0.3.2.22-3.

- The OCGS LRA will be revised to credit monitoring of the protective coating on the exterior surfaces of the drywell in the sand bed region in accordance with the requirements of ASME Section XI, Subsection IWE during the period of extended operation. The 5 drywell bays that have not yet been inspected will be inspected prior to the period of extended operation. This is new commitment 3.0.3.2.22-4.

- The OCGS LRA will be revised to credit performing periodic confirmatory UT inspections of the drywell shell in the sand bed region. The initial UT measurements will be taken prior to entering the period of extended operation and then every 10 years thereafter. The UT measurements will be taken from inside the drywell at the same locations where the UT measurements were taken in 1996. During the initial UT inspections of the sand bed region from inside the drywell, conducted prior to entering the period of extended operation, an attempt will be made to locate and evaluate some of the locally thinned areas identified in the 1992 inspection from the exterior of the drywell. This is new commitment 3.0.3.2.22-5.

In its letter dated May 1, 2006 (AmerGen Letter No. 2130-06-20328), the applicant committed to the following:

- The OCGS LRA will be revised to state that during the next UT inspections of the drywell sand bed region, an attempt will be made to locate and evaluate some of the locally thinned areas identified in the 1992 inspection. This is new commitment 3.0.3.2.22-6.

- The OCGS LRA will be revised to credit inspecting the coating on all 20 bays of the suppression chamber (torus) during the period of extended operation. The frequency of inspection will be every other refueling outage for the current coating system. Should the coating system be replaced, the inspection frequency and scope will be re-evaluated. The inspection scope will, as a minimum, meet the requirements of ASME, Subsection IWE. This is new commitment 3.0.3.2.22-7.

- The OCGS LRA will be revised to credit improving the monitoring and trending of torus design margins, and to develop refined acceptance criteria and thresholds for entering coating defects and unacceptable pit depths into the Corrective Action process for further evaluation. These improvements will be incorporated into the inspection implementing documents prior to the next performance of these inspections, which is also prior to the period of extended operation. This is new commitment 3.0.3.2.22-8.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.27. Contingent upon the inclusion of new commitments 3.0.3.2.22-1 through 3.0.3.2.22-8 and the resolutions to open items, the project team found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.2.22.7 Conclusion

On the basis of its audit and review of the applicant's program and the plant-specific operating experience, and discussions with the applicant's technical staff, the staff initiated three open items regarding the plant-specific augmented inspections included in the applicant’s ASME Section XI, Subsection IWE program to assess whether the program is adequate to manage aging of the degraded primary containment during the extended period of operation.

The project team also reviewed the UFSAR Supplement for this AMP and found that, contingent upon the inclusion of new commitments 3.0.3.2.22-1 through 3.0.3.2.22-8 and the resolutions to the open items, it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.23 ASME Section XI, Subsection IWF (OCGS AMP B.1.28)

In OCGS LRA, Appendix B, Section B.1.28, the applicant stated that OCGS AMP B.1.28, "ASME Section XI, Subsection IWF," is an existing plant program that is consistent with GALL AMP XI.S3, "ASME Section XI, Subsection IWF," with an exception and enhancements.

3.0.3.2.23.1 Program Description

The applicant stated, in the OCGS LRA, that this program consists of periodic visual examination of ASME Section XI Class 1, 2, 3 and MC components and piping support members for loss of mechanical function and loss of material. Bolting is also included with these components, inspecting for loss of material and for loss of preload by inspecting for missing, detached, or loosened bolts. Procurement controls and installation practices, defined in plant procedures, ensure that only approved lubricants and torque are applied. The program is implemented through corporate and station procedures, which provide inspection and acceptance criteria consistent with the requirements of ASME Section XI, 1995 Edition with 1996 Addenda.

3.0.3.2.23.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.28 is consistent with GALL AMP XI.S3, with an exception and enhancements.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.28, including PBD-AMP-B.1.28 ?ASME Section XI, Subsection IWF," Rev. 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.S3.

The project team reviewed those portions of the ASME Section XI, Subsection IWF program for which the applicant claims consistency with GALL AMP XI.M6 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's ASME Section XI, Subsection IWF program conforms to the recommended GALL AMP XI.S3, "ASME Section XI, Subsection IWF," with the exception and enhancements as described below.

3.0.3.2.23.3 Exceptions to the GALL Report

The applicant stated, in the OCGS LRA, that an exception to the GALL Report program elements is as follows:

Element: Program Description

Exception: NUREG-1801 evaluation covers the 2001 edition including the 2002 and 2003 Addenda, as approved in 10 CFR 50.55a. The current Oyster Creek ISI Program Plan for the fourth ten-year inspection interval effective from October 15, 2002 through October 14, 2012, approved per 10CFR50.55a, is based on the 1995 ASME Section XI Code, including 1996 addenda. The next 120-month inspection interval for Oyster Creek will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a twelve months before the start of the inspection interval.

The GALL Report includes the following recommendations for the ?program description" related to the exception taken:

> *Program Description*: 10 CFR 50.55a imposes the inservice inspection (ISI) requirements of the ASME Code, Section XI, for Class 1, 2, 3, and MC piping and components and their associated supports. Inservice inspection of supports for ASME piping and components is addressed in Section XI, Subsection IWF. This evaluation covers the 2001 edition1 including the 2002 and 2003 Addenda, as approved in 10 CFR 50.55a. ASME Code Section XI, Subsection IWF constitutes an existing mandated program applicable to managing aging of ASME Class 1, 2, 3, and MC supports for license renewal.

The project team noted that the 1995 ASME Section XI Code, including 1996 addenda, was the then-current edition incorporated into 10 CFR 50.55a at the time the applicant was required to declare its inspection basis for the current 10-year IWE inspection interval. The applicant will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a twelve months before the start of the next 120-month inspection interval. Since this is consistent with the intent of the GALL guidance, the project team does not consider this to be an actual exception to GALL. On this basis, the project team found this exception acceptable.

3.0.3.2.23.4 Enhancements

The applicant stated, in the OCGS LRA, that the enhancement in meeting the GALL Report program elements is as follows:

Element:	1. Scope of Program
Enhancement:	Enhancement activities, which are in addition to the existing Oyster Creek ASME Section XI, Subsection IWF program, consist of including additional MC supports inside the Torus, Torus Support – Base Plate and Saddle, Inner Support Column & Outer Support Column) and inspection of underwater MC supports for loss of material due to corrosion and loss of mechanical function (Torus Internal – Downcomer Brace Support (underwater), Vent Header Ring Header Support (above water), Vent System Inner Support Column (above and below water) and Vent System Outer Support Column (above and below water)). Enhancements will be implemented prior to entering the period of extended operation.

The GALL Report includes the following recommendations for the ?scope of program" program element related to the enhancement stated:

> *1. Scope of Program*: For Class 1 piping and component supports, Subsection IWF (1989 edition) refers to Subsection IWB for the inspection scope and schedule. According to Table IWB-2500-1, only 25% of nonexempt supports are subject to examination. Supports exempt from examination are the supports for piping systems that are exempt from examination, according to pipe diameter or service. The same supports are inspected in each 10-year inspection interval. For Class 2, 3, and MC piping and component supports, Subsection IWF (1989 edition) refers to Subsections IW C, IWD, and IWE for the inspection scope and schedule. According to Table

IWC-2500-1, 7.5% of nonexempt supports are subject to examination for Class 2 systems. The same supports are inspected in each 10-year inspection interval. No specific numerical percentages are identified in Subsections IWD and IWE for Class 3 and Class MC, respectively.

The project team asked the applicant for clarifications about this enhancement, in order to better understand what MC supports are currently in the OCGS IWF program, what MC supports are being added to the OCGS program, and also to confirm that all MC supports under the jurisdiction of IWF are included in the OCGS IWF program. In response, the applicant stated that

(a) The MC supports that are currently included in the existing IWF inspection program are:

Existing Containment Program – IWE (above water line – internal)
E1.20 Downcomers
E1.20 Ring Header within Torus
E1.20 Vent Lines – DW to Torus Vent Lines
Existing Torus Exterior – IWF MC Supports
F1.40 Torus Support – Sway Braces

(b) The MC supports that will be added to the scope of the IWF inspection program for the license renewal period are:

Torus (Internal) – IWF MC Supports
Torus Support – Base Plate and Saddle
Torus Support – Inner Support Column
Torus Support – Outer Support Column
Torus Internal – Downcomer Brace Support (underwater)
Vent Header Ring Header Support (Above water)
Vent System Inner Support Column (above and below water)
Vent System Outer Support Column (above and below water)

OC-1 ISI Program Plan Section 4.0 Component Support ISI Plan contains the current inspection details for MC supports. Additional work will be done with the components identified in (b) above to confirm the current inspection practice. All MC supports will be included.

(c) The specific underwater supports that will be added to the scope of the IWF inspection program for the license renewal period are:

Downcomer Brace Supports (underwater)
Vent System Inner Support Column (above and below water)
Vent System Outer Support Column (above and below water)

The current inspection program and inspection details for the underwater supports identified in (c) above are not formalized. OCGS does perform underwater inspections of the torus for removal of sludge or debris (FME), inspect suction strainers for damage or obstruction, improve water clarity, assess coating and reestablish the coating barrier in deficient area. The applicant stated that implementing procedures for the B.1.28 inspection program for all underwater MC supports will be complete before the period of extended operation. The project team determined that the applicant's response sufficiently defined the enhanced scope for inspection of MC supports.

On this basis, the project team found this enhancement acceptable since when the enhancement is implemented, OCGS AMP B.1.28, "ASME Section XI, Subsection IWF," will be consistent with GALL AMP XI.S3 and will provide additional assurance that the effects of aging will be adequately managed.

3.0.3.2.23.5 Operating Experience

The applicant stated, in the OCGS LRA and the program basis document, that the component support ISI program invokes the requirements of the ASME Section XI Code. Because the ASME Code is a consensus document that has been widely used over a long period, it has been shown to be generally effective in managing aging effects in Class 1, 2, and 3 components and their integral attachments in light-water cooled power plants. The Operating Experience (OE) of the ISI program did not show any adverse trend of its performance. Problems identified would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. There is sufficient confidence that the Component Support ISI program as described in the Oyster Creek ISI program plan will effectively monitor the condition of the component supports within LR boundaries that are subject to an indoor air, containment atmosphere or treated water environment, so that their design function will be maintained during the extended license period. Appropriate guidance for reevaluation, repair or replacement is provided for any indication of degradation detected by the OC ISI program. Periodic self-assessments of the ISI program are performed to identify the areas that need improvement to maintain the quality performance of the program.

The applicant's operating experience review process includes both external and internal sources. External operating experience may include such things as INPO documents (e.g., SOERs, SERs, SENs, etc.), NRC documents (e.g., GLs, LERs, INs, etc.), General Electric documents (e.g., RCSILs, SILs, TILs, etc.), and other documents (e.g., 10CFR Part 21 Reports, NERs, etc.). Internal operating experience may include such things as event investigations, trending reports, and lessons learned from in-house events as captured in program notebooks, self-assessments, and in the 10 CFR Part 50, Appendix B corrective action process.

The applicant identified the following examples of operating experience to provide objective evidence that the component support ISI program is effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

> Challenges were identified in the NIS-1 Owner's Data Report for Inservice Inspections for the first period of the Fourth Inservice Inspection interval, submitted to the NRC on 2/16/2005. This report covered examinations conducted between October 28, 2002, and November 22, 2004, in accordance with the ASME Code. From the initial sample size of 40 rod hangers, 2.5% were found to be unacceptable. Scope expansion was required due to unacceptable as-found conditions on rod hangers. The systems involved were: Isolation Condenser, Core Spray System, Standby Liquid Control Shutdown Cooling, Reactor Water Clean Up, Reactor Recirc, Control Rod Drive, Containment Spray, Feedwater and Reactor Building Closed Cooling Water System piping supports, ASME Code Class 1 & 2. Rod hangers were the initial problems. The second scope expansion of rod hangers found zero failures. No Items were returned to service based solely on evaluation. All were restored/reworked to their intended design configuration.
>
> Another challenge that was corrected was a loss of preload (without loss of mechanical function) for 3 spring cans. The load settings were found outside the tolerance

(Reference CAP's 02004-3311 and -3341 along with A2078197). The spring cans with the load settings out of spec did not affect the sample expansion. A "root cause" failure evaluation was documented in AR A2078197 Eval. 23. Reinspections have been scheduled as part of ISI program for the next outage.

A focused-area self-assessment at OCGS indicated that Code Cases and Relief Requests were not easily found in the program documents and the listings were incomplete. The ISI Program plan was updated to include a summary of all Relief Requests in effect in Section 4 of the ISI plan and to include a listing of all Code Cases invoked in the plan. This example provides objective evidence that program deficiencies are identified and entered into the corrective action process and that the program is updated as necessary to ensure that it remains effective for condition monitoring of piping and components within the scope of license renewal. The above corrective action issue is identified in OCGS CAP O2004-1736.

A focused-area self-assessment at OCGS indicated that although a Relief Request for examination of a reactor pressure vessel support skirt weld had been granted, no provision to augment the ASME Code-required surface examination with a volumetric (UT) examination of the restricted area was addressed. A new exam record was added to the ISI database to reflect the required UT examination. This example provides objective evidence that program deficiencies are identified and entered into the corrective action process and that the program is updated as necessary to ensure that it remains effective for condition monitoring of piping and components within the scope of license renewal. . The above corrective action issue is identified in OCGS CAP O2004-1736.

The applicant concluded that the Oyster Creek ASME Section XI, Subsection IWF program is effective in managing the effects of aging.

The project team asked the applicant to provide additional information about the findings and resolution for the ?challenges” identified in the most recent IWF inspections (1st inspection period of the 4th inspection interval). In response, the applicant stated that the systems involved were: Isolation Condenser, Core Spray System, Standby Liquid Control Shutdown Cooling, Reactor Water Clean Up, Reactor Recirc, Control Rod Drive, Containment Spry, Feedwater and Reactor Building Closed Cooling Water System piping supports, ASME Code Class 1 & 2. The initial sample size was 40 and percentage found to be unacceptable was 2.5%. Loss of material due to corrosion was not identified. One case was a loss of preload which was corrected and the 3 spring cans had the load settings outside the tolerance. However, there was not a compromise of intended function. The applicant referenced CAPs 02004-331, 02004 -3341, and A2078197. The final sample size, after scope expansion, was 51 and the percentage found to be unacceptable was 4%. No supports were returned to service based on evaluation. All were restored/reworked to its intended design configuration. AR-Eval A2078197 E23 (provided to the project team) contains the "root cause" failure evaluation. Re-inspections have been scheduled as part of ISI program at the next outage.

The project team reviewed several CAPs and noted problems with supports in the Core Spray System dating back to 2000. The project team asked the applicant to provide information on corrective action taken to prevent recurrence. In response, the applicant stated that the Core Spray had a long history of hydraulic transients, which over the years caused support damage of various degrees. Some of the corrective actions taken, which mitigated these concerns are:

1. Installation of a Keep Full system

2. Installation of Frequency Controllers on the Test Valves V-20-26 and V-20-27, which slow down the opening stroke.

3. Modification of the pump recirculation piping to provide a continuous venting path and minimize the risk of piping voiding.

4. Implemented weekly PM to verify the system is filled and vented.

5. Modification of the counter weight assisted check valves (i.e., V-20-51 and V-20-52) to minimize the risk of sticking open. They were converted to regular swing check valves after malfunctioning of V-20-51 was determined to be the root cause for some water hammer transients experienced in Core Spray System 2 .

The applicant stated that all the deficient supports found during 1R20 (2004) are scheduled for re-inspection during 1R21 (2006) .

The project team determined that the applicant’s course of action for the 2 occurrences discussed above provide confirmation that its IWF program is effective.

The project team reviewed the operating experience provided in the OCGS LRA and the program basis document, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant’s ASME Section XI, Subsection IWF program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.2.23.6 <u>UFSAR Supplement</u>

The applicant provided its UFSAR Supplement for the ASME Section XI, Subsection IWF program in OCGS LRA, Appendix A, Section A.1.28, which states that the ASME Section XI, Subsection IWF aging management program is an existing program that consists of periodic visual examination of ASME Section XI Class 1, 2, 3 and MC components and piping support members for loss of mechanical function and loss of material. Bolting which is included with these components is monitored for loss of material and loss of preload by inspecting for missing, detached, or loosened bolts. Identification of any aging effects would initiate evaluation and establishment of corrective actions. The requirements of ASME Section XI, Subsection IWF are implemented in accordance with 10 CFR 50.55(a). The scope of the program will be enhanced to include additional MC supports, and require inspection of underwater supports for loss of material due to corrosion and loss of mechanical function and loss of preload on bolting by inspecting for missing, detached, or loosened bolts. Procurement controls and installation practices, defined in plant procedures, ensure that only approved lubricants and torque are applied. Enhancements to the program will be implemented prior to entering the period of extended operation.

The project team also reviewed the License Renewal Commitment List contained in the LRA Table A.5, to confirm that the scope of the program will be enhanced and the enhancement implemented prior to the extended period of operation. This is item 28 in LRA Table A.5.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.28, found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.2.23.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report, are consistent with the GALL Report. In addition, the project team has reviewed the exception and the associated justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. Also, the project team has reviewed the enhancements and determined that the implementation of the enhancements prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The project team also reviewed the UFSAR Supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.24 Structure Monitoring Program (OCGS AMP B.1.31)

In OCGS LRA, Appendix B, Section B.1.31, the applicant stated that OCGS AMP B.1.31, "Structures Monitoring Program," is an existing plant program that is consistent with GALL AMP XI.S6, "Structures Monitoring Program," with enhancements.

Subsequent to submittal of the LRA, the applicant added the Forked River Combustion Turbine (FRCT), the Meteorological Tower, and the Radio Communications System to the OCGS license renewal scope, in response to staff RAIs related to scoping and screening. The applicant credited the structures monitoring program for aging management of structural components and the external surfaces of mechanical components. This is consistent with the LRA. In AmerGen letter 2130-05-20239 dated December 9, 2005, Appendix D, the applicant provided its latest revision to the OCGS structures monitoring program, AMP B.1.31, to reflect the increased scope. Also included in the aforementioned letter was a revised FSAR Supplement, Section A.1.31 of the LRA, and a revised LRA commitment list for AMP B.1.31, to identify the increased scope of the program. The project team's assessment of OCGS AMP B.1.31 is based on the revised structures monitoring program provided in the December 9, 2005 AmerGen letter, which covers these new additions to the OCGS license renewal scope.

3.0.3.2.24.1 Program Description

The applicant stated, in the OCGS LRA, that this program provides for aging management of structures and structural components, including structural bolting, within the scope of license renewal. The program was developed based on guidance in Regulatory Guide 1.160, Revision 2, ?Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," and NUMARC 93-01, ?Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 2, to satisfy the requirement of 10 CFR 50.65, ?Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants."

The applicant stated that the scope of the program also includes condition monitoring of masonry walls and water-control structures as described in the Masonry Wall Program and in the RG 1.127, inspection of water-control structures associated with nuclear power plants, aging management program. As a result, the program elements incorporate the recommendations of NRC Bulletin 80-11, ?Masonry Wall Design," the guidance in NRC IN 87-67, ?Lessons Learned from Regional Inspections of Licensee Actions in Response to Bulletin 80-11," and the recommendations of NRC Regulatory Guide 1.127, ?Inspection of Water-Control Structures Associated with Nuclear Power Plants."

The applicant further stated that the program relies on periodic visual inspections by qualified personnel to monitor structures and components for applicable aging effects. Specifically, concrete structures are inspected for loss of material, cracking, and a change in material properties. Steel components are inspected for loss of material due to corrosion. Masonry walls are inspected for cracking, and elastomers will be monitored for a change in material properties. Earthen structures associated with water-control structures and the fire pond dam will be inspected for loss of material and loss of form. Component supports will be inspected for loss of material, reduction or loss of isolation function, and reduction in anchor capacity due to local concrete degradation. Exposed surfaces of bolting are monitored for loss of material, due to corrosion, loose nuts, missing bolts, or other indications of loss of preload. The program relies on procurement controls and installation practices, defined in plant procedures, to ensure that only approved lubricants and proper torque are applied consistent with the NUREG-1801 Bolting Integrity Program.

The applicant further stated that the scope of the program will be enhanced to include structures that are not monitored under the current term but require monitoring during the period extended operation. Details of the enhancements are discussed below.

The applicant stated that the inspection frequency is every four (4) years; except for submerged portions of water- control structures, which will be inspected when the structures are dewatered, or on a frequency not to exceed 10 years. The program contains provisions for more frequent inspections to ensure that observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

3.0.3.2.24.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.31 is consistent with GALL AMP XI.S6, with enhancements. The project team noted that the applicant did not identify an exception in the OCGS LRA to AMP XI.S6 in the GALL Report. The exception is discussed below.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.31, including PBD-AMP-B.1.31, ?Structures Monitoring program," Rev. 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.S6. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.31 and associated basis documents to determine consistency with GALL AMP XI.S6.

During the course of the audit, the project team asked the applicant to clarify a number of aspects of its structures monitoring program. The applicant's clarifications helped the project team to assess the program's consistency with the GALL Report.

The project team reviewed those portions of the structures monitoring program for which the applicant claims consistency with GALL AMP XI.S6 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's structures monitoring program conforms to the recommended GALL AMP XI.S6, with the exceptions and enhancements described below.

3.0.3.2.24.3 Exceptions to the GALL Report

The applicant did not identify an exception in the OCGS LRA to AMP XI.S6 in the GALL Report. However, based on the reconciliation from draft January 2005 NUREG-1801, Rev. 1 to the approved September 2005 NUREG-1801, Rev. 1, the applicant identified an exception to AMP XI.M36 in the GALL Report, the external surfaces monitoring program. This new exception is documented in PBD-AMP-B.1.31, which is the program basis document for the structures monitoring program. In PBD-AMP-B.1.31, the applicant stated the following exception to the GALL Report program element:

Element: 4. Detection of Aging Effects

Exception: The program takes exception to the inspection frequency of at least once per refueling cycle specified in NUREG-1801, XI.M36, Rev. 1, for monitoring external surfaces of mechanical components. The specified frequency by the Oyster Creek (structures monitoring) program is every 4 years.

The GALL Report identified the following recommendations for the ?detection of aging effects" program element in AMP XI.S6 associated with the exception taken:

> 4. *Detection of Aging Effects*: For each structure/aging effect combination, the inspection methods, inspection schedule, and inspector qualifications are selected to ensure that aging degradation will be detected and quantified before there is loss of intended functions. Inspection methods, inspection schedule, and inspector qualifications are to be commensurate with industry codes, standards and guidelines, and are to also consider industry and plant-specific operating experience. Although not required, ACI 349.3R-96 and ANSI/ASCE 11-90 provide an acceptable basis for addressing detection of aging effects. The plant-specific structures monitoring program is to contain sufficient detail on detection to conclude that this program attribute is satisfied.

In reviewing this exception, the project team recognized that the applicant identified this exception to the recommendations in the GALL Report for the external surfaces monitoring program, AMP XI.M36, since the OCGS structures monitoring program was credited to monitor the external surfaces of components. Therefore, the project team also reviewed the recommendations in the GALL Report for the ?detection of aging effects" program element for AMP XI.M36, which are the following:

> *4. Detection of Aging Effects:* Degradation of steel surfaces cannot occur without the degradation of the paint or coating. Confirmation of the integrity of the paint or coating is an effective method for managing the effects of corrosion on the steel surface. A visual inspection is conducted for component surfaces at least once per refueling cycle. This frequency accommodates inspections of components that may be in locations that are normally only accessible during outages. System walkdowns are normally

> performed on a frequency that exceeds once per fuel cycle. Surfaces that are inaccessible or not readily visible during plant operations and refueling outages are inspected at such intervals that would ensure the components intended function is maintained. The intervals of inspections may be adjusted as necessary based on plant-specific inspection results and industry experience.

The applicant provided the following technical justifications for this exception in the program basis document:

> The frequency of 4 years specified for monitoring of exterior surfaces of mechanical components is consistent with the frequency specified for exterior surfaces of supporting structures. The 4-year frequency is consistent with industry guidelines and has proven effective in detecting loss of material due to corrosion, and change in material properties of structural elastomer on exterior surfaces of structures. Consequently this frequency will also be effective for detecting loss of material and change in material properties on exterior surfaces of mechanical components before an intended function is impacted.
>
> Industry and plant-specific operating experience review has not identified any instances of significant loss of material or change in material properties of external surfaces of mechanical components subject to indoor air environment.
>
> Mechanical components subject to outdoor air are constructed from stainless steel, aluminum, which are not susceptible to accelerated corrosion, or carbon steel components protected by protective coatings such as galvanizing, or painting. Plant operating experience indicates that monitoring of exterior surfaces of components made of these materials and protective coatings on a frequency of 4 years provides assurance that loss of material will be detected before an intended function is affected.
>
> Studies by EPRI provide a corrosion rate curve for carbon steels. This curve was constructed from 55 individual tests representing at least five different steels and six different test locations and environments. The curve shows 0.926 mils per year thickness loss during the first 1 ½ years, decreasing to 0.21 mils per year after 15 ½ years. EPRI also conducted corrosion tests of ASTM A-36 structural steel at four nuclear plants located in Elma and Richland, Washington; and Midland, Michigan. The tests were conducted for up to 24 months. EPRI concluded that based on the test results the corrosion rate is 0.5 mils per year. If the corrosion rate is conservatively taken as 0.926 mils per year, then the loss of material projected for 4 years is less than 4 mils. This loss of material is insignificant and will not impact the intended function of mechanical components.

The applicant was asked to confirm that the OCGS LRA would be revised to include this new exception in the structures monitoring program, AMP B.1.31. The applicant stated that this new exception would be included in the OCGS LRA for AMP B.1.31.

In its letter dated March 30, 2006 (ML060950408), the applicant committed to revise the OCGS LRA to add the exception identified in its reconciliation document for the structures monitoring program, which states that the program takes exception to the inspection frequency of at least once per refueling cycle specified in NUREG-1801, XI.M36, Rev. 1, for monitoring external surfaces of mechanical components. The specified frequency by the Oyster Creek (structures monitoring) program is every 4 years**. This is Audit Commitment 3.0.3.2.24-1.**

On the basis that monitoring the external surfaces of mechanical components on a 4-year frequency is adequate to provide assurance of their structural integrity, the project team determined that this exception is acceptable.

3.0.3.2.24.4 Enhancements

The applicant identified, in the program basis document (PBD-AMP-B.1.31) for the structures monitoring program, the following enhancements to the GALL Report elements:

Enhancement 1

Element: 1. Scope of Program

Enhancement: The following structures and components will be added to the scope of the program.

- Chlorination facility, Exhaust Tunnel, Heating Boiler house, Oyster Creek Substation, Fire Pond Dam, and Miscellaneous Yard Structures
- Panels and enclosures
- Exposed surfaces of concrete anchors and embedments.
- Penetration seals other than fire seals. Fire seals are included with fire protection activities
- Doors other than fire rated doors. Fire rated doors are included with fire protection activities.
- Structural seals (secondary containment, and flood barriers)
- Components supports including, electrical cable trays, electrical conduit, tubing, HVAC ducts, instrument racks, battery racks, and supports for piping and components that are not within the scope of ASME Section XI, Subsection IWF.
- Concrete surfaces exposed to salt water and fire pond water (RG Guides 1.127).
- Miscellaneous steel
- Foundation and anchorage of equipment, tanks, panels and enclosures.
- Duct banks, and manholes
- Offsite power transmission tower
- Submerged steel and wooden components at the Intake Structure and Canal, Dilution Structure, and Fire Pond Dam.
- Liner for containment drywell and reactor building sumps
- Steel and wooden bulkheads

The scope of the program will also be enhanced to include inspection of exterior surfaces of Oyster Creek and Forked River Combustion Turbines (FRCT) mechanical components that are not covered by other programs, including exterior surfaces of HVAC ducts, damper housings and duct closure bolting within the scope of license renewal. Components that will be added to scope of the program include piping components, valves, tanks, vessels, etc. located in indoor or outdoor air environments. The scope of the program is limited to components whose exterior surfaces are not monitored by other programs such as ASME Section XI, ISI Programs and fire protection activities.

The program will also be enhanced to require periodic sampling of ground water to confirm that the environment is non-aggressive for buried reinforced concrete during the period of extended operation.

The scope of the program will be enhanced to include Station Blackout System (FRCT) structures, structural components, and phase bus enclosure assemblies. Inspection frequency, inspection methods, and acceptance criteria will be the same as those specified for other structures in scope of the program.

Concrete foundations for Station Blackout System (FRCT) structures will be inspected for cracking and distortion due to increased stress level from settlement that may result from degradation of the inaccessible wooden piles.

The program will be enhanced to include Inspection of Meteorological Tower Structures. Inspection and acceptance criteria will be the same as those specified for other structures in the scope of the program.

The program will be enhanced to include inspection of exterior surfaces of piping and piping components associated with the Radio Communications system, located at the meteorological tower site, for loss of material due to corrosion. Inspection and acceptance criteria will be the same as those specified for other external surfaces of mechanical components.

The GALL Report identifies the following recommendations for the ?scope of program” program element associated with the enhancement taken:

1. *Scope of Program*: The applicant specifies the structure/aging effect combinations that are managed by its structures monitoring program.

In the program basis document, PBD-AMP.B.1.31, the applicant provided the following basis for these enhancements:

GALL specifies that the applicant defines the scope of this AMP for license renewal. The current OCGS structures monitoring program was developed and implemented to meet the regulatory requirements of 10 CFR 50.65, Maintenance Rule, USNRC Regulatory Guide 1.160, and NUMARC 93-01, ?Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The program includes masonry walls evaluated in accordance with NRC IEB 80-11, ?Masonry Wall Design" and incorporates guidance in NRC IN 87-67, ?Lessons Learned from Regional Inspection of Licensee Actions in Response to IE Bulletin 80-11." The program elements also incorporate the recommendations of NRC Regulatory Guide 1.127, ?Inspection of Water-Control Structures Associated with Nuclear Power Plants."

The program is implemented through a station procedure, which identifies the structures and structural components within the scope of the Maintenance Rule; however, some of the structures in the scope of License Renewal are not covered by the scope of the Maintenance Rule. Thus, the scope of the program was enhanced to include additional structures and structural components that are in scope of license renewal. In some cases the added structure or component is included in the existing inspections; however there are no procedural requirements to perform the inspection for the particular structure or component. In this case the enhancement consists of revising procedures to specifically address the structure or component.

The project team reviewed the enhancements to ?scope of program" and the applicant's basis, and determined that, with these enhancements, the applicant's structures monitoring program is consistent with GALL, for this program element.

<u>Enhancement 2</u>

Element: 3. Parameters Monitored or Inspected

Enhancement: The existing Oyster Creek Structures Monitoring Program implementing procedure will be revised to include the following enhancements:

- For concrete structures, the program will be enhanced to require visual inspection for change in material properties due to leaching of calcium hydroxide and aggressive chemical attack. The visual inspection consists of observing concrete surfaces for significant leaching or disintegration. Concrete structures will also be observed for a reduction in anchor capacity due to local concrete degradation. This will be accomplished by visual inspection of concrete surfaces around anchors for cracking, and spalling.

- The program will be enhanced to add loss of material due to corrosion for structural steel members and other steel components, such as embedments, panels and enclosures, doors, siding, metal deck, structural bolting, anchors, and miscellaneous steel.

- The program will be enhanced to require inspection of penetration seals and structural seals, for change in material properties by inspecting the seals for cracking and hardening.

- The program will be enhanced to require monitoring of vibration isolators, associated with component supports other than those covered by ASME XI, Subsection IWF, for reduction or loss of isolation function by inspecting the isolators for cracking and hardening.

- The program will be enhanced to require visual inspection of external surfaces of mechanical steel components that are not covered by other programs for loss of material due to corrosion, and change material properties, due to leaching of calcium hydroxide and aggressive chemical attack for reinforced concrete. Accessible wooden piles and sheeting will be inspected for loss of material and change in material properties. Concrete foundations for Station Blackout System structures will be inspected for cracking and distortion due to increased stress level from settlement that may result from degradation of the inaccessible wooden piles. Mechanical elastomers, such as hoses, will be inspected for a change in material properties by observing the elastomer for cracking and hardening. These enhanced requirements are applicable to both Oyster Creek and FRCT mechanical components.

- Groundwater will be monitored for pH, chlorides, and sulfates.

- The program will be enhanced to require visual inspection of external surfaces of mechanical steel components that are not covered by other programs for leakage from or onto external surfaces, worn, flaking, or oxide-coated surfaces, corrosion stains on thermal insulation, and protective coating degradation (cracking and flaking). These enhanced requirements are applicable to both Oyster Creek and FRCT mechanical components.

  Note: This is a new commitment based on the reconciliation of this aging management program from draft January 2005 NUREG-1801, Rev. 1 to the approved September 2005 NUREG-1801, Rev. 1.

- The program will be enhanced to require removal of piping and component insulation to permit visual inspection of insulated surfaces. Removal of insulation will be on a sampling basis that bounds insulation material type, susceptibility of insulated piping or component material to potential degradations that could result from being in contact with insulation, and system operating temperature.

These enhanced requirements are applicable to both Oyster Creek and FRCT mechanical components.

- The program will be enhanced to require inspection of exterior surfaces of HVAC ducts, damper housings, for loss of material and HVAC closure bolting for loss of material and loose or missing bolts nuts. These enhanced requirements are applicable to both Oyster Creek and FRCT components.

The GALL Report identifies the following recommendations for the ?parameters monitored or inspected" program element associated with the enhancement taken:

> 3. *Parameters Monitored or Inspected*: For each structure/aging effect combination, the specific parameters monitored or inspected are selected to ensure that aging degradation leading to loss of intended functions will be detected and the extent of degradation can be determined. Parameters monitored or inspected are to be commensurate with industry codes, standards and guidelines, and are to also consider plant-specific operating experience. Although not required, ACI 349.3R-96 and ANSI/ASCE 11-90 provide an acceptable basis for selection of parameters to be monitored or inspected for concrete and steel structural elements and for steel liners, joints, coatings, and waterproofing membranes (if applicable). If necessary for managing settlement and erosion of porous concrete subfoundations, the continued functionality of a site dewatering system is to be monitored. The plant-specific structures monitoring program is to contain sufficient detail on parameters monitored or inspected to conclude that this program attribute is satisfied.

In its letter dated March 30, 2006 (ML060950408), the applicant committed to enhance the structures monitoring program (B.1.31) to require visual inspection of external surfaces of mechanical steel components that are not covered by other programs for leakage from or onto external surfaces, worn, flaking, or oxide-coated surfaces, corrosion stains on thermal insulation, and protective coating degradation (cracking and flaking). These enhanced requirements are applicable to both Oyster Creek and FRCT mechanical components. **This is Audit Commitment 3.0.3.2.24-2.**

As justification for the adequacy of the enhancements to this program element, the applicant stated:

> For each structure and aging effect combination, the specific parameters monitored or inspected are selected to ensure that aging degradation leading to loss of intended functions will be detected and the extent of degradation can be determined. Parameters monitored or inspected are based on aging effects identified for Oyster Creek material and environment combinations documented in PP-15, Standard Materials, Environments and Aging Effects. Where required, the existing aging management activities are enhanced to ensure that parameters monitored will detect degradations that could lead to a loss of an intended function.
>
> Parameters monitored under the existing program include the following:

- Reinforced concrete structures are monitored for loss of material, and cracking. The aging effects are monitored by inspecting concrete surfaces for spalling, scaling, rebar corrosion, rust stain, water stains, water intrusion, rebar exposure, disintegration, and cracking

- Structural steel members and connections are monitored for loose or missing bolts, which are considered loss of preload, cracked welds, and loose or distorted structural members.

- Masonry block walls are monitored for cracks, and loose blocks

- The intake canal slopes and embankments are monitored for loss of form by inspecting for cracks, sink holes, and embankment collapse.

Program enhancements required to ensure that parameters monitored will detect degradations that could lead to a loss of an intended function are summarized below. In some cases the enhancement is included as part of existing activities. However, there are no procedural requirements or commitment to perform the activity. For these cases, the enhancement consists of revising the program implementing procedure to proceduralize the performed inspections.

Parameters monitored or inspected are developed to implement the requirements of 10 CFR 50.65, ?Maintenance Rule," USNRC Regulatory Guide 1.160, IEB 80-11, and RG. 1.127 for water control structures. The parameters monitored or inspected are based on industry standards, including ACI 349.3R-96, ?Evaluation of Existing Nuclear Safety-Related Concrete Structures," NEI 96-03, ?Guideline for Monitoring the Condition of Structures at Nuclear power Plants," NUMARC 93-01, ?Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," and NUREG-1522, ?Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures."

Concrete parameters monitored or inspected are based on ACI 349.3R-96. Structural steel and steel liner inspection parameters are based on design codes and standards including American Institute of Steel Construction (AISC). ANSI/ASCE 11-90 is not specifically referenced in program implementing documents, however its elements are incorporated in the program.

Oyster Creek structures are founded on highly dense soil and settlement is not a concern. Observed total settlements of the reactor building foundation have ranged from 2/3 to ¾ inches, which compares well with the predicted settlement of less that one inch. Thus a settlement monitoring is not required; nor is a de-watering system relied upon to control settlement. Porous concrete is not incorporated into the design of Oyster Creek sub-foundation.

The enhanced Oyster Creek Structures Monitoring Program contains sufficient detail on parameters monitored or inspected to conclude with reasonable assurance that NUREG-1801 XI.S6 and XI.M36, ?External Surfaces Monitoring Program," attributes are satisfied.

The project team reviewed the enhancements to ?parameters monitored or inspected" and the applicant's justification for its adequacy, and determined that, with these enhancements, the applicant's structures monitoring program is consistent with GALL, for this program element.

Enhancement 3

Element: 4. Detection of Aging Effects

Enhancement: The program will be enhanced to require inspection of submerged water-control structures when dewatered, or on a frequency not to exceed 10 years.

The GALL Report identifies the following recommendations for the ?Detection of Aging Effects" program element associated with the enhancement taken:

> 4. *Detection of Aging* Effects: For each structure/aging effect combination, the inspection methods, inspection schedule, and inspector qualifications are selected to ensure that aging degradation will be detected and quantified before there is loss of intended functions. Inspection methods, inspection schedule, and inspector qualifications are to be commensurate with industry codes, standards and guidelines, and are to also consider plant-specific operating experience. Although not required, ACI 349.3R-96 and ANSI/ASCE 11-90 provide an acceptable basis for addressing detection of aging effects. The plant-specific structures monitoring program is to contain sufficient detail on detection to conclude that this program attribute is satisfied.

The project team noted that the 10 year inspection frequency for submerged portions of water-control structures was not consistent with a new commitment identified in PBD-AMP-B.1.32 for the OCGS submerged water-control structures aging management program, which states that a baseline inspection of submerged water control structures will be performed prior to entering the period of extended operation. A second inspection will be performed 6 years after this baseline inspection and a third 8 years after the second. After each inspection an evaluation will be performed to determine if the identified degradations warrant more frequent inspections or corrective actions. The applicant was asked to explain why B.1.31 was not consistent with the new B.1.32 commitment. In response to the project team's inquiry, the applicant stated that both the program basis document, PBD-AMP-B.1.31, and the OCGS LRA will be revised to add an enhancement to the OCGS structures monitoring program, AMP B.1.31, to include an inspection frequency for submerged water-control structures that is consistent with the enhancement described in PBD-AMP-B.1.32, Section 2.4 Summary of Enhancements.

In its letter dated April 17, 2006 (ML061150320), the applicant committed to revise the structures monitoring program (AMP B.1.31) in the OCGS LRA to include an inspection frequency for submerged portions of water control structures that is consistent with the new commitment identified in PBD-AMP-B.1.32 for the submerged water control structures program. The new commitment states that a baseline inspection of submerged water control structures will be performed prior to entering the period of extended operation. A second inspection will be performed 6 years after this baseline inspection and a third 8 years after the second. After each inspection an evaluation will be performed to determine if the identified degradations warrant more frequent inspections or corrective actions. **This is Audit Commitment 3.0.3.2.24-3.**

The applicant stated that the program basis document PBD-AMP-B.1.31 for the structures monitoring program (AMP B.1.31) will also be revised to include an inspection frequency for submerged portions of water control structures that is consistent with the new commitment identified in PBD-AMP-B.1.32 for the submerged water control structures program. The new commitment states that a baseline inspection of submerged water control structures will be performed prior to entering the period of extended operation. A second inspection will be performed 6 years after this baseline inspection and a third 8 years after the second. After each inspection an evaluation will be performed to determine if the identified degradations warrant more frequent inspections or corrective actions.

The project team’s assessment of AMP B.1.32 is documented in Section 3.0.3.2.25 of this audit report. The project team found the revised inspection frequency to be acceptable, because the applicant's baseline inspection schedule and its commitment to evaluate the identified degradations provides assurance that the effects of aging will be adequately managed for the period of extended operation.
The project team reviewed the revised enhancement to ?detection of aging effects,” and determined that, with this enhancement, the applicant’s structures monitoring program is consistent with GALL, for this program element.

<u>Enhancement 4</u>

Element:	6. Acceptance Criteria
Enhancement:	The existing Oyster Creek Structures Monitoring Program implementing procedure will be revised to require that qualified individuals evaluate identified degradations on external surfaces of mechanical components. Acceptance criteria will be consistent with industry standards, design codes and guidelines, including ANSI or ASME as applicable. This is applicable to Oyster Creek and FRCT exterior surfaces of mechanical components. Acceptance criteria to establish if groundwater is aggressive for concrete structures (pH <5.5, or chlorides > 500 ppm, or sulfates > 1500 ppm) will be consistent with industry standards, and NUREG-1801.

The GALL Report identifies the following recommendations for the ?acceptance criteria” program element associated with the enhancement taken:

> 6. *Acceptance Criteria*: For each structure/aging effect combination, the acceptance criteria are selected to ensure that the need for corrective actions will be identified before loss of intended functions. Acceptance criteria are to be commensurate with industry codes, standards and guidelines, and are to also consider plant-specific operating experience. Although not required, ACI 349.3R-96 provides an acceptable basis for developing acceptance criteria for concrete structural elements, steel liners, joints, coatings, and waterproofing membranes. The plant-specific structures monitoring program is to contain sufficient detail on acceptance criteria to conclude that this program attribute is satisfied.

The applicant provided the following basis for the enhancements:

> Inspection results are evaluated by qualified engineers based on acceptance criteria selected for each structure/aging effect to ensure that the need for corrective actions would be identified before loss of intended functions.
>
> Identified degradation are evaluated by qualified individuals based on industry codes, standards, and guidelines including ACI 318, ACI 349.3R, and AISC. Development of

acceptance criteria considers plant specific operating experience. These criteria are directed at identification and evaluation of degradations that may affect the ability of the structure or component to perform its intended function.

ACI 349.3R-96 was used to develop acceptance criteria for concrete structural elements.

The enhanced Oyster Creek Structures Monitoring Program requires that identified degradations be assessed and evaluated by qualified engineering personnel, considering the extent of the degradation using design basis codes and standards that include ACI 318, ACI 349.3R, AISC, and ASME/ANSI. The program implementing procedure provides sufficient details on acceptance criteria for structures and exterior surfaces of mechanical components to ensure that significant degradations are identified and corrected before a loss of an intended function.

The project team reviewed the enhancements to ?acceptance criteria" and the applicant's basis, and determined that, with these enhancements, the applicant's structures monitoring program is consistent with GALL, for this program element.

The project team finds that, with the enhancements described above, the applicant's structures monitoring program will meet the intent of the program described in GALL AMP XI.S6.

3.0.3.2.24.5 Operating Experience

The applicant stated, in the OCGS LRA and PBD-AMP-B.1.31, that it reviews operating experience from both external and internal (also referred to as in-house) sources. External operating experience may include such things as INPO documents (e.g., SOERs, SERs, SENs, etc.), NRC documents (e.g., GLs, LERs, INs, etc.), Westinghouse documents (e.g., TBs, etc.), General Electric documents (e.g., RCSILs, SILs, TILs, etc.), and other documents (e.g., 10CFR Part 21 Reports, NERs, etc.). Internal operating experience may include such things as event investigations, trending reports, and lessons learned from in-house events as captured in program notebooks, self-assessments, and in the 10 CFR Part 50, Appendix B corrective action process.

The applicant further stated that demonstration that the effects of aging are effectively managed is achieved through objective evidence that the structures monitoring program has been effective in identifying aging effects of structures and structural components through visual detection of degrading components, and plant maintenance activities in place prior to the implementation of the structures monitoring program. The enhanced program will provide the same effectiveness for managing the aging effects of structures, exterior surfaces of mechanical components, and commodities added to the scope of the program.

The applicant described the following examples of operating experience to provide objective evidence that the structures monitoring program is effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

Concrete Cracking:

Reactor Building Exterior – a review of documentation going back to early 1997 indicates the identification of cracking on the exterior surfaces of the Reactor Building. Notable cracking has been observed on the west wall with minor cracking on the east and south walls. The documented review of the condition indicates the cause to be from combination of concrete shrinkage and temperature changes. The reason for the differences in degree of cracking on the west wall as opposed to the east and south walls is attributed to the fact the west wall does not have a scored exterior wall at the control joints unlike the east and south walls. The condition has been monitored during Maintenance Rule structure monitoring inspections; documented, and dispositioned not to be a structural capability concern, but a concern over the life of the plant because of rebar corrosion. Repairs were completed on areas deemed to be of concern for long-term operation of the plant. The conditions continue to be monitored and assessed through routine structure inspections. This example provides objective evidence that concrete cracking will be detected, and that engineering evaluations and corrective actions are performed prior to the loss of intended function.

Reactor Building Interior – on the interior of the west wall above 95-foot elevation there is documented crack in the proximity to the Standby Liquid Control System. This crack has been cosmetically repaired and occurred in the score joint. No structural concerns were documented in the inspection reports. This example provides objective evidence that cracking is detected, and that engineering evaluations and corrective actions are performed prior to any loss of intended function.

Drywell Shield Wall – Cracking of the drywell shield wall is documented in the NRC SEP review of the plant under Topic III-7B. The cracking is located above elevation 95 foot on the cylindrical portion of the shield wall. The cracking is attributed to elevated temperatures experienced over the life of the plant at this location. The crack patterns have been mapped, and inspected repeatedly. There have been no changes in the condition, which would indicate a structural concern was present or impending. This example provides objective evidence that concrete cracking will be detected, and that updates to the program are made as necessary to ensure that any corrective actions are performed prior to the loss of intended function.

Spent Fuel Pool Support Beams – In the middle of 1980’s cracking around the spent fuel pool area of the reactor building was identified. Subsequently crack monitors were installed to monitor crack growth and a finite element analysis was performed to evaluate the design. Conclusions were drawn the cracking was predictable from the stresses found and further NDT determined the cracks not to be deep. The conclusion drawn was there was no structural concern, crack changes were not discernable, and that further monitoring of the crack monitors was not justified. But, continual monitoring of the areas is within the scope of the Structure Monitoring Program, and would be conducted on a periodic basis per the program. This example provides objective evidence that any detected cracking will be evaluated, and that the program will be updated as necessary to enhance monitoring such that any required corrective actions are performed prior to the loss of intended function.

Intake Structure and Canal – Inspection of the intake canal, performed in 2001, identified cracks and fissures, voids, holes, and localized washout of coatings that protect embankment slopes from erosion. The degradations were evaluated and determined not to impact the intended function of the intake canal. These degradations are tracked for repair in accordance with the corrective action process. This example provides objective evidence that any detected deficiencies will be evaluated to determine if corrective actions are necessary to prevent loss of intended function, and that deficiencies are entered into the 10 CFR Part 50, Appendix B, Corrective Action process.

Ventilation Tunnel – A recent inspection identified localized spalling of the columns beneath the fan pad structure in the ventilation tunnel. The spalling has been attributed to failure to install the engineered configuration during construction. This condition is being monitored on a more frequent basis and corrective actions have been identified. The Mechanical/Structural Group on site is acquiring funding for the repairs. This example provides objective evidence that deficiencies are detected, evaluated, and tracked on an enhanced schedule to ensure corrective action prior to loss of intended function.

Inspections conducted in 2002, concluded that degradations discussed above have not become worse and remain essentially the same as identified in previous inspections. In addition minor cracking, rust stains, water stains, localized exposed rebars and rebar corrosion, and damage to siding were observed. The degradations were evaluated and determined not to have an impact on the structural integrity of affected structures. AR #A2050926 was generated to track painting of the steel platform near the top of the ventilation stack. These examples provide objective evidence that deficiencies are evaluated and corrective actions taken prior to loss of intended function.

Additional searches of Oyster Creek corrective action process (CAP) database identified 217 instances of corrosion cases on exterior surfaces of mechanical components and structures. For 216 cases, engineering evaluation concluded that the observed corrosion is limited to surface rust and does not impact the intended function of the component or structure. For the remaining one case, a unistrut support member for 3/8" diameter tubing, corrosion was more extensive but the unitstrut was evaluated and determined capable of performing its intended function. These examples provide objective evidence that deficiencies are entered into the corrective action process and that engineering evaluations are performed to determine what if any corrective actions need to be taken prior to loss of intended function.

The applicant concluded that the operating experience of the structures monitoring program did not show any adverse trend in performance. Problems identified would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. There is sufficient confidence that the implementation of Structures Monitoring Program as described in the implementing procedures (125.6 and 2400-GMM-3900.52) will effectively manage aging effects through the period of extended operation.

The project team noted that the applicant’s discussion of operating experience identified three conditions of concrete degradation: cracking of the RB walls; cracking of the drywell shield wall due to high temperature; and cracking of the spent fuel storage pool concrete support beams. A fourth condition, degradation of the intake canal, is also addressed in LRA Section B.1.32, in the operating experience discussion for water-control structures. For each of the first three conditions of concrete degradation, the project team asked the applicant to provide additional information describing the degradation, the assessment performed, the acceptance criteria applied, future monitoring recommendations, and any corrective action taken. The project team also asked the applicant to describe the monitoring activities that are, or will be conducted under the structures monitoring program for each of the three regions. In its response, the applicant indicated that the requested information is included in the Structures monitoring program basis document (PBD-AMP-B.1.31) notebook, and would be available for the staff's review during the second AMP audit. The project team reviewed this information during the second AMP audit. The project team conducted additional reviews of these conditions as part of the AMR audit. See Section 3.5.2 of this audit report for documentation of the project team’s review and assessment.

The project team reviewed the operating experience provided in the OCGS LRA and PBD-AMP-B.1.31, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant's Structures Monitoring Program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.2.24.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the structures monitoring program in OCGS LRA, Appendix A, Section A.1.31. The applicant subsequently revised the UFSAR supplement in it response to staff RAI 2.5.1.15-1, which states that the structures monitoring program is an existing program that was developed to implement the requirements of 10 CFR 50.65 and is based on NUMARC 93-01, ?Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 2 and Regulatory Guide 1.160, ?Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 2. The program includes elements of the Masonry Wall Program and the RG 1.127, Inspection of Water-Control Structures Associated With Nuclear Power Plants aging management program. The program relies on periodic visual inspections to monitor the condition of structures and structural components, structural bolting, component supports, masonry block walls, water-control structures, the Fire Pond Dam, exterior surfaces of mechanical components that are not covered by other programs, and HVAC ducts, damper housings, and HVAC closure bolting. The program relies on procurement controls and installation practices, defined in plant procedures, to ensure that only approved lubricants and proper torque are applied to bolting in scope of the program.

The scope of the program will be enhanced to include structures and structural components that are not currently monitored, including Station Blackout System structures and phase bus enclosure assemblies, and Meteorological Tower Structures; but determined to be in the scope of license renewal, submerged structures, component supports not covered by other programs, the Fire Pond Dam, exterior surfaces of Oyster Creek and Forked River Combustion Turbine mechanical components that are not covered by other programs, including exterior surfaces of HVAC ducts, damper housings, and closure bolting. The program will also be enhanced to require removal of piping and component insulation on a sampling basis to allow visual inspection of insulated surfaces. The program will also be enhanced to require sampling and testing of groundwater every 4 years to confirm that the soil environment is non-aggressive to below-grade concrete structures. Other program scope enhancements include inspection of piping and piping components associated with the Radio Communications system located at the meteorological tower site. The enhancements will be made prior to entering the period of extended operation.

Inspection criteria will be enhanced to provide reasonable assurance that change in material properties, cracking, loss of material, loss of form, reduction or loss of isolation function, reduction in anchor capacity due local degradation, and loss of preload are adequately managed so that the intended functions of structures and components within the scope of the program are maintained consistent with the current licensing basis during the period of extended operation.

Inspection frequency is every four (4) years; except for submerged portions of the water-control structures, which will be inspected when dewatered or on a frequency not to exceed ten (10) years. The program contains provisions for more frequent inspections to ensure that observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

In Section 3.0.3.2.24.1 of this audit report, the project team identified Audit Commitment 3.0.3.2.24-3, to revise the inspection frequency for submerged portions of the water-control structures.

The project team reviewed the UFSAR Supplement to confirm that it provides an adequate summary description of AMP B.1.31, including the enhancements. The project team also reviewed the license renewal commitment list Table A.5, which was also revised in the response to staff RAI 2.5.1.15-1, to confirm that all enhancements are identified.

- In its letter dated March 30, 2006 (ML060950408), the applicant committed t the following: Enhance the structures monitoring program (B.1.31) to require visual inspection of external surfaces of mechanical steel components that are not covered by other programs. (Audit Commitment 3.0.3.2.24-2)

- Add the exception identified in its reconciliation document for the structures monitoring program, which states that the program takes exception to the inspection frequency of at least once per refueling cycle specified in NUREG-1801, XI.M36. (Audit Commitment 3.0.3.2.24-1)

In its letter dated April 17, 2006 (ML061150320), the applicant committed to revise the structures monitoring program (AMP B.1.31) in the OCGS LRA to include an inspection frequency for submerged portions of water control structures that is consistent with the new commitment identified in PBD-AMP-B.1.32 for the submerged water control structures program. (Audit Commitment 3.0.3.2.24-3)

The applicant's license renewal commitment list and UFSAR update are to be revised to reflect these new commitments.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.31. Contingent upon the inclusion of audit commitments 3.0.3.2.24-1 through 3, the project team found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.2.24.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report, are consistent with the GALL Report. Also, the project team has reviewed the enhancements and determined that the implementation of the enhancements prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The project team also reviewed the UFSAR Supplement for this AMP and, contingent upon the inclusion of audit commitments 3.0.3.2.24-1 to 3.0.3.2.24-3, the project team found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.25 RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (OCGS AMP B.1.32)

In OCGS LRA, Appendix B, Section B.1.32, the applicant stated that OCGS AMP B.1.32, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," is an existing plant program that is consistent with GALL AMP XI.S7, "RG 1.127, Inspection of Water-control Structures Associated with Nuclear Power Plants," with enhancements.

3.0.3.2.25.1 Program Description

The applicant stated, in the OCGS LRA, that this program is part of the Structures Monitoring Program (OCGS AMP B.1.31). It is based on the guidance provided in RG 1.127 and ACI 349.3R and will provide for periodic inspection of the Intake Structure and Canal (UHS), the Fire Pond Dam, and the Dilution structure. The program will be used to manage loss of material, cracking, and change in material properties for concrete components, loss of material and change in material properties for wooden components, and loss of material, and loss of form for the dam, and the canal slopes.

The applicant also stated that inspection frequency is every four (4) years; except for submerged portions of the structures, which will be inspected when the structures are de-watered, or on a frequency not to exceed 10 years. The program will be enhanced, as noted below, to provide assurance that water-control structures aging effects are adequately managed during the period of extended operation.

3.0.3.2.25.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.32 is consistent with GALL AMP XI.S7, with enhancements.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.32, including PBD-AMP-B.1.32 "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," Rev. 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.S7. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.32 and associated bases documents to determine consistency with GALL AMP XI.S7.

During the first on-site AMP audit on October 3-7, 2005, the project team requested additional information about AMP B.1.32, and the applicant provided written responses. These are discussed below.

The project team noted that the Program Description for AMP B.1.32 stated that the inspection frequency is every four (4) years, except for submerged portions of the structures, which will be inspected when the structures are dewatered, or on a frequency not to exceed 10 years. GALL AMP XI.S7 identifies an inspection frequency of 5 years. The project team asked the applicant to explain why the 10 year inspection frequency is not identified as an exception to the GALL AMP, and to provide the technical basis for concluding that a 10 year inspection frequency is sufficient for submerged portions of structures.

In response, the applicant stated:

> The 5 year inspection frequency identified in GALL AMP XI.S7 is based on Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants. Oyster Creek is not committed to inspect underwater structures on a frequency of 5 years as explained below. The Oyster Creek RG 1.127, Inspection of Water Control Structures Associated with Nuclear Power Plants was reviewed by NRC and approved

the program. For this reason the 10 year frequency was not identified as an exception to the GALL AMP.

The Oyster Creek original design did not commit to the requirements of RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants. However in response to NUREG-0822, Integrated Plant Safety Assessment Systematic Evaluation Program (SEP) Topic III-3.C, Oyster Creek evaluated water control structure consistent with the recommendations of RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants, and presented to the NRC the evaluation results and the proposed Oyster Creek RG. 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants surveillance program. In a letter dated June 24, 1982, the NRC provided the results of its review and comments on the proposed surveillance program. This letter and NUREG-1382, Safety Evaluation Report related to the full-term operating license for Oyster Creek Nuclear Generating Station formed the basis for the existing Oyster Creek RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program.

The existing Oyster Creek RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program did not commit to the inspection frequency of 5 years specified in Regulatory Guide 1.127 revision 1. Inspection of water control structures is included in the Oyster Creek Structures Monitoring Program (B.1.31); except for the Fire Pond Dam, which is inspected under the New Jersey Dam Safety Standards, N.J.A.C 7:20-1.1 et seq.

The Oyster Creek Structures Monitoring Program (B.1.31) requires inspection of accessible water control structures on a 4 year frequency consistent with the frequency for implementing the requirements of the 10 CFR Part 50.65, Maintenance Rule. The program considers underwater structures inaccessible and requires inspection only when they become accessible. For license renewal, we enhanced the program to require inspection of underwater structures before entering the period of extended operation, and on a frequency of 10 years during the period of extended operation. After each inspection, the identified degradations will be evaluated to determine if more frequent inspections are warranted to ensure that the intended function of the water control structures is not adversely impacted. The 10 year frequency is selected based on plant operating experience with the Intake Structure and Canal. This operating experience identified concrete degradations, however none were significant enough to impact the intended function of the structure.

The project team also noted that LRA Appendix B, Section B.0.5 identifies AMP B.1.32 as an existing program. The Program Description stated that this AMP is part of the Structures Monitoring Program. The scope of the six enhancements listed for AMP B.1.32 encompass many of the elements that normally would be part of an existing inspection program for water-control structures. Consequently, the project team asked the applicant to (a) specifically describe the scope of the currently existing program, including the structures and components in the scope of the existing program; the aging effects that are monitored; the inspection methods employed; and the inspection frequency; and (b) specifically describe the scope of AMP B.1.32, including the structures and components in the scope of AMP B.1.32, the aging effects that are monitored, the inspection methods employed, and the inspection frequency.

In response, the applicant stated:

(a) RG 1.127, Inspection of Water-Control Structures is implemented through the Structures Monitoring Program, B.1.31. The scope of the program includes the intake structure and canal, and the dilution structure. Components monitored include earthen control structures (intake canal, embankment) and reinforced concrete structures. The aging effects monitored include cracks, sinkholes, and embankment collapse of the intake canal embankment. Concrete structures are monitored for cracks, spalling and scaling, rebar exposure, rust stain, structural settlement, and rebar corrosion. The method of inspection is visual inspection. Inspection frequency of accessible areas is every 4 years. Inaccessible areas of the structures are inspected whenever an opportunity occurs.

(b) The scope of the enhanced program includes structures and components that are in scope of the existing program. In addition, the scope is enhanced to include the fire pond dam inspection, inspection of submerged components of the intake structure and canal, the dilution structure, the fire pond dam, and the earthen dike between the intake and the discharge canal. The aging effects monitored include cracks, sinkholes, and embankment collapse of the intake canal embankment. Concrete structures are monitored for cracks, spalling and scaling, rebar exposure, rust stain, structural settlement, and rebar corrosion. Enhancement to the aging effects include the addition of monitoring concrete structures for change in material properties due to leaching of calcium hydroxide, inspection of wooden components for loss of material and change in material properties, and loss of material due to corrosion for steel components. The method of inspection is visual inspection. Inspection frequency of accessible areas is every 4 years. Inaccessible areas are inspected whenever an opportunity occurs.

In an update to its response, the applicant stated:

The program will be enhanced to require performing a baseline inspection of submerged water control structures prior to entering the period of extended operation. A second inspection will be performed 6 years after this baseline inspection and a third 8 years after the second. After each inspection an evaluation will be performed to determine if the identified degradations warrant more frequent inspections or corrective actions. This constitutes a new enhancement not previously identified in the LRA.

The project team also noted that the first enhancement to B.1.32 identified that the program will provide for monitoring of trash racks. In LRA Table 3.5.2.1.11, the Structures Monitoring Program is credited for aging management of trash racks. The project team asked the applicant to explain this apparent discrepancy.

In response, the applicant stated:

?The trash racks are not identified in NRC Regulatory Guide 1.127, Inspection or Water-Control Structures Associated with Nuclear Power Plants, as component of the water control structures. The CLB does not credit the trash racks for the safety-related intended function of the Ultimate Heat Sink (UHS). However, we recognize that the trash racks provide a filter function that prevents debris from potentially clogging ESW pumps. For this reason, we included the trash racks in the scope of the Rule and credit the Structures Monitoring Program for managing their aging. Also as stated in Appendix B.1.32, RG 1.127, Inspection or Water-Control Structures Associated with Nuclear Power Plants, the program is implemented through the Structures Monitoring Program B.1.31.

> Thus the aging effects of the trash racks are monitored by the same program used to monitor water control structures."

Following the first AMP on-site audit in October 2005, the applicant prepared PBD-AMP- B.1.32, which provides an assessment of consistency between the program elements of AMP B.1.32 and the program elements of GALL AMP XI.S7. The applicant incorporated its responses to the project team's audit questions into PBD-AMP- B.1.32. Consequently, the project team's assessment of AMP B.1.32 was substantially based on review of PBD-AMP-B.1.32, in addition to the LRA. PBD-AMP-B.1.32 identified an exception and one additional enhancement, both related to the inspection frequency for submerged structures, that were not identified in the LRA. These are discussed below, under exceptions and enhancements.

The project team reviewed those portions of the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power program for which the applicant claims consistency with GALL AMP XI.S7 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power program conforms to the recommended GALL AMP XI.S7, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power," with the exception and enhancements as described below.

The project team noted that the applicant did not state an exception to the GALL program in the OCGS LRA as stated in OCGS PBD-AMP-B.1.32.

3.0.3.2.25.3 Exceptions to the GALL Report

The following exception is stated in OCGS PBD-AMP-B.1.32 to the GALL Report program elements:

Element:	4. Detection of Aging Effects
Exception:	The Oyster Creek RG 1.127, Inspection of Water Control Structures Associated With Nuclear Power Plants takes exception to the inspection frequency specified in NUREG-1801 XI.S7, RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants. This exception is applicable only to submerged structures. This is a new exception not previously identified in the LRA.

The GALL Report includes the following recommendations for the ?detection of aging effects" program element:

> *4. Detection of Aging Effects*: RG 1.127 describes periodic inspections, to be performed at least once every five years.

As justification for the exception, the applicant stated:

> During the NRC aging management program (AMP) review audit (October 23-27, 2005), the staff indicated that the 10-year inspection frequency is not consistent with the 5-year frequency specified in NUREG-1801 Program XI.S7, RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants and requested the technical basis for concluding a 10 year inspection frequency is sufficient for submerged

portions of water control structures. Oyster Creek indicated that the review of the CLB concluded that the existing Oyster Creek RG 1.127, Inspection of Water Control Structures Associated With Nuclear Power Plants program is based on SEP Topic III-3.C commitments, which do not address submerged structures. The 10-year inspection frequency was determined sufficient, based on operating experience, to detect significant age related degradations before an intended function of the water control structures is adversely impacted. Additionally Oyster Creek will perform a baseline inspection of underwater structures and evaluate identified age related degradations to establish if there is a need for more frequent inspection to provide assurance that aging effects are adequately managed. The staff noted that the present existing operating experience related to underwater structure is not sufficient for the staff to conclude that the 10-year inspection frequency is adequate.

As a result of the staff's concern, Oyster Creek agreed to perform a baseline inspection of submerged water control structures prior to entering the period of extended period of operation. A second inspection will be performed 6 years after the baseline inspection. A third inspection will be performed 8 years after the second inspection. Following each inspection, the identified degradations will be evaluated to determine if more frequent inspections are warranted or there is a need for corrective actions to ensure that age related degradations are adequately managed. This constitutes a new exception not previously identified in the LRA.

In its letter dated March 30, 2006 (ML060950408), the applicant committed to revise the OCGS LRA to add the exception to the inspection frequency specified in NUREG-1801 XI.S7 stated in program basis document PBD-AMP-B.1.32. The applicant has committed to a baseline inspection prior to entering the period of extended period of operation, a second inspection 6 years after the baseline inspection, and a third inspection 8 years after the second inspection, and has committed to evaluate the identified degradations to determine if more frequent inspections are warranted. The project team determined that the exception was acceptable because the applicant’s baseline inspection schedule for submerged water control structures and its commitment to evaluate the identified degradations ensures that the effects of aging will be adequately managed for the extended period of operation. The project team identified the applicant’s revised commitment to inspect submerged water control structures as **Audit Commitment 3.0.3.2.25-1.**

3.0.3.2.25.4 Enhancements

The applicant stated, in the OCGS LRA and/or in PBD-AMP-B.1.32, that the enhancements in meeting the GALL Report program elements are as follows:

(1) The program will provide for monitoring of submerged structural components and trash racks.

(2) Parameters monitored will be enhanced to include change in material properties, due to leaching of calcium hydroxide, and aggressive chemical attack.

(3) Add the requirement to inspect steel components for loss of material, due to corrosion.

(4) Add the requirement to inspect wooden piles and sheeting for loss of material and change in material properties.\

(5) The program will provide for periodic inspection of components submerged in salt water (intake structure and canal, dilution structure) and in the water of the fire pond dam.

(6) The program will be enhanced to include periodic inspection of the fire pond dam for loss of material and loss of form.

(7) The program will be enhanced to require performing a baseline inspection of submerged water control structures prior to entering the period of extended operation. A second inspection will be performed 6 years after this baseline inspection and a third 8 years after the second. After each inspection an evaluation will be performed to determine if the identified degradations warrant more frequent inspections or corrective actions. [This constitutes a new enhancement not previously identified in the LRA.]

The applicant identified the GALL program elements affected by the enhancements to be 1. Scope of Program; 3. Parameters Monitored or Inspected; and 4. Detection of Aging Effects.

The project team noted that ?enhancement” (7) is not an enhancement to meet the GALL Report recommendations. The applicant’s new commitment for inspection of submerged water control structures, while a significant improvement over the original LRA commitment, is still an exception to the GALL Report recommendations. The project team evaluated this ?enhancement” as an exception, in 3.0.3.2.25.3 of this audit report. Since ?enhancement” 7 is the only enhancement that affects program element 4, ?detection of aging effects,” there was no need for the project team to review any enhancements for program element 4.

Element: 1. Scope of Program

Enhancement: The OCGS AMP will be enhanced to include the following:

(1) The program will provide for monitoring of submerged structural components and trash racks.

(5) The program will provide for periodic inspection of components submerged in salt water (intake structure and canal, dilution structure) and in the water of the fire pond dam.

(6) The program will be enhanced to include periodic inspection of the fire pond dam for loss of material and loss of form.

The GALL Report includes the following recommendations for the ?scope of program” program element related to this enhancement:

1. Scope of Program: RG 1.127 applies to water-control structures associated with emergency cooling water systems or flood protection of nuclear power plants. The water-control structures included in the RG 1.127 program are concrete structures; embankment structures; spillway structures and outlet works; reservoirs; cooling water channels and canals, and intake and discharge structures; and safety and performance instrumentation.

The applicant provided its basis for concluding that, with the identified enhancements, AMP B.1.32 will be consistent with GALL program element 1. Scope of Program. The applicant stated that the Oyster RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants applies to water control structures associated with the emergency cooling water system. Water control structures in scope of license renewal are included in the scope of B.1.32. These structures are the intake structure and canal (ultimate heat sink), the dilution structure, and the intake structure trash racks. Structural components and commodities of the structures that are monitored under the existing program include reinforced concrete members, and earthen water control structures (intake canal, embankments. The enhanced program will include the fire pond dam and its various components, including the spillway, and embankments.

The applicant further indicated that there are no water control structures that are credited for flood protection, and there are no safety and performance instrumentation such as seismic instrumentation, horizontal and vertical movement instrumentation, uplift instrumentation, and other instrumentation incorporated in the design of Oyster Creek water control structures.

The applicant stated that the implementing documents for this aging management program are listed in PBD-AMP- B.1.32, Table 5.1. The commitment numbers under which these implementing documents are being revised are also listed in Table 5.1.

The project team compared the program scope of AMP B.1.32, including enhancements, against the program scope of GALL Report AMP XI.S7, and found them to be consistent.

On this basis, the project team found the enhancements to the ?scope of program" element acceptable since when enhancements are implemented, OCGS AMP B.1.32, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power," will be consistent with GALL AMP XI.S7 and will provide additional assurance that the effects of aging will be adequately managed.

Element: 3. Parameters Monitored or Inspected

Enhancement: The OCGS AMP will be enhanced to include the following:

(2) Parameters monitored for concrete will be enhanced to include change in material properties, due to leaching of calcium hydroxide, and aggressive chemical attack.

(3) Parameters monitored will include inspection of steel components for loss of material due to corrosion and pitting.

(4) Parameters monitored will include inspection of wooden piles and sheeting for loss of material and change in material properties.

The GALL Report includes the following recommendations for the ?parameters monitored or inspected" program element related to this enhancement:

> *3. Parameters Monitored or Inspected*: RG 1.127 identifies the parameters to be monitored and inspected for water-control structures. The parameters vary depending on the particular structure. Parameters to be monitored and inspected for concrete structures include cracking, movements (e.g., settlement, heaving, deflection), conditions at junctions with abutments and embankments, erosion, cavitation, seepage, and leakage. Parameters to be monitored and inspected for earthen embankment structures include settlement, depressions, sink holes, slope stability (e.g., irregularities in

alignment and variances from originally constructed slopes), seepage, proper functioning of drainage systems, and degradation of slope protection features. Further details of parameters to be monitored and inspected for these and other water-control structures are specified in Section C.2 of RG 1.127.

The applicant provided its basis for concluding that, with the identified enhancements, AMP B.1.32 will be consistent with GALL program element 1. Scope of Program. The applicant stated that parameters monitored or inspected are consistent with the guidance specified in Section C.2 of RG 1.127. For reinforced concrete components, it includes loss of material due to various aging mechanisms, including erosion and cavitation, cracking due to various aging mechanisms including settlement, and change in material properties due to leaching of calcium hydroxide. Steel components associated with earthen water control structures (intake canal, embankments), fire pond dam, and trash racks are monitored for loss of material due to pitting and corrosion. Wooden components are monitored or inspected for loss of material and change in material properties. Slopes for earthen water control structures at junction with abutments are monitored for loss of material and loss of form (cracks, sinkholes, erosion, and slope instability). The applicant further stated that parameters monitored and inspected for earthen water control structures include settlement, depressions, sink holes, slope stability (e.g., irregularities in alignment and variances from originally constructed slopes), and loss of slope protection liner. These parameters are considered loss of material and loss of form. Earthen water control structures have no drainage systems, and thus monitoring of drainage systems is not applicable.

The project team compared the parameters monitored or inspected in AMP B.1.32, including enhancements, against the parameters monitored or inspected in GALL Report AMP XI.S7, and found them to be consistent.

On this basis, the project team found the enhancements to the ?parameters monitored or inspected" program element acceptable since when enhancements are implemented, OCGS AMP B.1.32, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power," will be consistent with GALL AMP XI.S7 and will provide additional assurance that the effects of aging will be adequately managed.

3.0.3.2.25.5 Operating Experience

The applicant stated, in the OCGS LRA, that the operating history of the intake structure and canal, and the dilution structure indicates that the structures are not experiencing significant degradation. Localized cracking and spalling of the Intake structure concrete was identified and repaired in mid 1980's. Recent inspection (2002) of the intake structure and the dilution structure noted some concrete spalling and cracking. However, these aging effects were determined insignificant and have no adverse impact on the intended functions of the structures. Inspection of the intake canal, performed in 2001, identified some cracks and fissures, voids, holes, and localized washout of coatings that protect embankment slopes from erosion. The degradations were evaluated and determined not to impact the intended function of the intake canal (UHS). The degradations are inspected periodically and evaluated to ensure that the intended function of the intake canal is not adversely impacted. The applicant's operating experience review concluded that the program is effective for managing aging effects of water-control structures.

During the first AMP on-site audit on October 3-7, 2005, the project team noted that the operating experience discussion in the LRA for AMP B.1.32 indicated that OCGS has experienced (1) degradation of the intake structure concrete that required repair in the 1980s;

(2) cracking and spalling of intake structure and dilution structure concrete identified in 2002; and (3) degradation of the intake canal identified in 2001. The two recent findings were dispositioned as acceptable, because the intended functions had not been impacted. For all three occurrences, the project team asked the applicant to provide the plant documentation that describes the degradation, the assessment performed, the acceptance criteria applied, future monitoring recommendations, and any corrective action taken.

In response, the applicant stated that the requested documentation is included in Oyster Creek RG 1.127, ?Inspection of Water-Control Structures Associated with Nuclear Power Plants" program basis document (PBD-AMP-B.1.32) Notebook and will be available for the staff's review during the AMP audit week (second AMP on-site audit, January 23-27, 2006).

During the second AMP on-site audit on January 23-27, 2006, the project team reviewed the discussion of operating experience in PBD-AMP-B.1.32.

The applicant stated, in PBD-AMP-B.1.32, that its review of industry operating experience noted that degradations have occurred in water control structures associated with nuclear power plants. The degradations were detected though the RG 1.127, Inspection of Water Control Structures Associated With Nuclear Power Plants aging management program and corrected before a loss of an intended function. The plant specific operating experience review also shows that degradations have occurred and have been identified through the Structures Monitoring aging management program which implements Oyster Creek RG 1.127, Inspection of Water Control Structures Associated With Nuclear Power Plants recommendations. The degradations were generally minor; but some required corrective actions to ensure that the intended function is maintained.

The applicant stated that it reviews operating experience from both external and internal (also referred to as in-house) sources. External operating experience may include such things as INPO documents (e.g., SOERs, SERs, SENs, etc.), NRC documents (e.g., GLs, LERs, INs, etc.), General Electric documents (e.g., RCSILs, SILs, TILs, etc.), and other documents (e.g., 10CFR Part 21 Reports, NERs, etc.). Internal operating experience may include such things as event investigations, trending reports, and lessons learned from in-house events as captured in program notebooks, self-assessments, and in the 10 CFR Part 50, Appendix B corrective action process.

The applicant described the following examples of operating experience, as objective evidence that the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program is effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

1. In 1985, GPUN launched an investigation to evaluate the structural condition of the intake structure. Cracking attributed to freeze-thaw and some corrosion of rebar were observed on the operating deck underside. In the1986 refueling outage, GPUN dewatered the north bay of the intake structure, cleaned up the marine growth on the concrete surface under the water line and performed additional inspections, including taking core-bores for compressive strength testing. Only a few areas with minor degradations were found under the water line. Degraded areas were repaired before the north bay was returned to service. The repaired areas were inspected again during the 1994 refueling outage. A few areas of re-occurring rebar corrosion were observed and repaired.

Similar degradations were observed on the operating deck of the south bay. The degradations were repaired during the 1988, 1989 refueling outage and re-inspected during the 1994 refueling outage. The inspection results of the south bay during the 1994 refueling outage showed that the structure is in good condition. Inspections performed in 2002 noted local spalling and cracking of concrete in addition to some rusted support members. The inspector concluded that the overall condition of the intake structure is structurally sound and acceptable to perform its intended function. The 2002 inspection also identified minor cracks on the lower deck walls of the dilution structure. The cracks were determined not to have an adverse impact on the intended function of the structure.

Inspection of the intake canal, performed in 2001, identified some cracks and fissures, voids, holes, and localized washout of coatings that protect embankment slopes from erosion. The degradations were evaluated and determined not to impact the intended function of the intake canal (ultimate heat sink). The degradations are inspected periodically and evaluated to ensure that the intended function of the intake canal is not adversely impacted.

2. The 1992 "Regular Inspection" of the fire pond dam identified two areas of the downstream sheeting that were bulging outward from the dam. To stabilize the situation, approximately 130 cubic yards of riprap was placed in the scour areas and along the entire downstream length of the spillway. Inspections performed in 2001 found no areas of erosion or structural instability. The inspection concluded that repairs made in 1992 seemed to have stabilized the spillway and no additional movement was noted during the inspection.

The 2004 "Informal Inspection" of the fire pond dam noted signs of erosion downstream of the right spillway wing wall, which has exposed the lower part of the bulkhead. This could compromise the integrity of the spillway wing wall and further triggered erosion of the area. However the dam and appurtenant structures are in a safe condition.

3. CAP 00360630 was issued in August 2005 as a result of low level in the north structure. The cause of the low water level was attributed to debris accumulation on the trash racks. Also the trash racks collapsed due to excessive load of the debris and hydrostatic pressure. Inspection and evaluation of the failure mechanism of the trash rack concluded that the failure is not age degradation related. Instead, the failure was due to a design feature of the trash racks purposely provided to fail under excessive load to avoid catastrophic failure of the intake structure.

The project team reviewed several applicant’s reports (see Attachment 5) documenting cited degradation occurrences and their resolution, and concluded that appropriate courses of action were taken.

The project team reviewed the operating experience provided in the OCGS LRA and PBD-AMP-B.1.32, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above industry and plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant’s RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.2.25.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program in OCGS LRA, Appendix A, Section A.1.32. It stated that the ?RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," aging management program is an existing condition monitoring program that is a part of the Structures Monitoring Program. The program requires periodic inspection of the Intake Structure and Canal (UHS), and the Dilution structure concrete for loss of material, cracking, and changes in material properties. Steel components are inspected for loss of material due to corrosion, and the earthen dike and canal slopes are monitored for loss of material and loss of form. The program will be enhanced to include periodic inspection of the Fire Pond Dam for loss of material and loss of form. Other enhancements include periodic inspection of submerged concrete, wood, and steel components for age related degradations. Inspection frequency is every four (4) years; except for submerged portions of the structures, which will be inspected when the structures are dewatered, or on a frequency not to exceed 10 years. Enhancements to the program will be implemented prior to entering the period of extended operation.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.32, and noted that the FSAR Supplement in the LRA does not reflect the applicant's latest revision to the inspection frequency for submerged structures. As part of Audit Commitment 3.0.3.2.25-1, the applicant needs to update the LRA Appendix A and Commitment Table A.5 information, to be consistent with this change. See Section 3.0.3.2.25.3 of this audit report. After revision, the FSAR supplement will provide an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.2.25.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report, are consistent with the GALL Report. Also, the project team has reviewed the enhancements and determined that the implementation of the enhancements prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared.
The project team also reviewed the UFSAR Supplement for this AMP and found that after revision it will provide an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.26 Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrument Circuits (OCGS AMP B.1.35)

In OCGS LRA, Appendix B, Section B.1.35, the applicant stated that OCGS AMP B.1.35, ?Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrument Circuits," is an existing plant program that is consistent with GALL AMP XI.E2, ?Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrument Circuits," with enhancements.

3.0.3.2.26.1 Program Description

In the OCGS LRA, the applicant stated that this program provides aging management for cables and connections used in sensitive instrumentation circuits with low-level signals.

The applicant stated that the cables of the intermediate range monitoring (IRM), local power range monitoring/average power range monitoring (LPRM/APRM), reactor building high-radiation monitoring, and air ejector offgas radiation monitoring systems are sensitive instrumentation circuits with low-level signals and are located in areas where the cables and connections could be exposed to adverse localized environments caused by heat, radiation, or moisture. These adverse localized environments can result in reduced insulation resistance, causing increases in leakage currents. This program considers the technical information and guidance provided in NUREG/CR-5643, ?Insights Gained From Aging Research," issued March 1992; IEEE Std. P1205-2000, ?IEEE Guide for Assessing, Monitoring, and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations"; SAND96-0344, ?Aging Management Guideline for Commercial Nuclear Power Plants—Electrical Cable and Terminations"; and EPRI TR-109619, ?Guideline for the Management of Adverse Localized Equipment Environments, Electric Power Research Institute," issued June 1999.

For the IRM and LPRM/APRM systems, the program is implemented by station procedures that are currently used to perform current/voltage (I/V) and time domain reflectometry (TDR) cable testing and have proven effective in determining the cable insulation condition. Testing is performed every refueling outage. Corrective action, such as cable replacement, is taken if a cable fails to meet the acceptance criteria of the cable test procedure. As recommended by GALL AMP XI.E2, a review of the cable testing results for cable aging degradation will be performed before the period of extended operation and every 10 years thereafter.

For the reactor building high-radiation monitoring and air ejector offgas radiation monitoring systems, the program is currently implemented by station procedures that are used to perform calibration testing required by the technical specifications. When an instrumentation channel is found to be out of tolerance or out of calibration, corrective action is taken, such as recalibration and circuit troubleshooting of the instrumentation cable system. As GALL AMP XI.E2 recommends, a review of the calibration testing results for cable aging degradation will be performed before the period of extended operation and every 10 years thereafter.

3.0.3.2.26.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.1.35 is consistent with GALL AMP XI.E2, with enhancements.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.35, including PBD-AMP-B.1.35, ?Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits," Revision 0, which assesses AMP elements' consistency with GALL AMP XI.E2. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.35 and associated bases documents to determine their consistency with GALL AMP XI.E2.

The project team reviewed those portions of the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrument Circuits Program for which the applicant claims consistency with GALL AMP XI.E2 and found that they are consistent with the GALL Report AMP. Furthermore, the project team concludes that the applicant's Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrument Circuits Program provides assurance that the aging management of conductor insulation resulting from heat, radiation, or moisture for electrical cables used in instrumentation circuits will be adequately performed. The project team found that the applicant's Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrument Circuits Program conforms to the recommended GALL AMP XI.E2, with the enhancements described below.

3.0.3.2.26.3 Exceptions to the GALL Report

None.

3.0.3.2.26.4 Enhancements

In the OCGS LRA, the applicant noted the following enhancements in meeting the GALL Report program elements:

Enhancement 1

Elements:	3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring and Trending
Enhancement:	Section XI.E2 of NUREG-1801 recommends a review of the calibration results for cable aging degradation once every 10 years. Calibration results are not currently reviewed for cable aging degradation. This program will be revised to include a review of the reactor building high-radiation monitoring and air ejector offgas radiation monitoring systems calibration results for cable aging degradation before the period of extended operation and every 10 years thereafter.

The GALL Report identified the following recommendations for the ?parameters monitored or inspected," ?detection of aging effects," and ?monitoring and trending" program elements associated with the enhancement:

3. Parameters Monitored or Inspected: The parameters monitored are determined from the specific calibration, surveillance, or testing performed and are based on the specific instrumentation circuit under surveillance or being calibrated, as documented in plant procedures.

4. Detection of Aging Effects: A review of calibration results or findings of surveillance programs can provide an indication of the existence of aging effects based on acceptance criteria related to instrumentation circuit performance. In cases in which a calibration or surveillance program does not include the cabling system in the testing circuit, or as an alternative to the review of calibration results described above, the applicant will perform cable system testing.

5. Monitoring and Trending: Trending actions are not included as part of this program because the ability to trend test results is dependent on the specific type of test chosen. However, test results that are trendable provide additional information on the rate of degradation.

In the OCGS LRA, the applicant stated that, as recommended by GALL AMP XI.E2, a review of the calibration testing results for cable aging degradation will be performed before the period of extended operation and every 10 years thereafter. By reviewing the results obtained during calibration, severe aging degradation will be detected before the loss of the cable's and/or connection's intended function.

On this basis, the project team found this enhancement acceptable because once these enhancements are implemented, OCGS AMP B.1.35 will be consistent with GALL AMP XI.E2 and will provide additional assurance that the effects of aging will be adequately managed.

Enhancement 2

Elements:	3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring and Trending
Enhancement:	Section XI.E2 of NUREG-1801 recommends a review of test results for cable aging degradation once every 10 years. Cable test results are not currently reviewed for cable aging degradation. This program will be revised to include a review of the LPRM/APRM and IRM system cable testing results for cable aging degradation before the period of extended operation and every 10 years thereafter.

The GALL Report identified the following recommendations for the ?parameters monitored or inspected," ?detection of aging effects," and ?monitoring and trending" program elements associated with the enhancement:

> *3. Parameters Monitored or Inspected*: The parameters monitored are determined from the specific calibration, surveillance, or testing performed and are based on the specific instrumentation circuit under surveillance or being calibrated, as documented in plant procedures.
>
> *4. Detection of Aging Effects*: A review of calibration results or findings of surveillance programs can provide an indication of the existence of aging effects based on acceptance criteria related to instrumentation circuit performance. In cases in which a calibration or surveillance program does not include the cabling system in the testing circuit, or as an alternative to the review of calibration results described above, the applicant will perform cable system testing.
>
> *5. Monitoring and Trending*: Trending actions are not included as part of this program because the ability to trend test results is dependent on the specific type of test chosen. However, test results that are trendable provide additional information on the rate of degradation.

In the OCGS LRA, the applicant stated that, as recommended by GALL AMP XI.E2, a review of cable test results for cable aging degradation will be performed before the period of extended operation and every 10 years thereafter. By reviewing the results obtained during cable testing, severe aging degradation will be detected before the loss of the cable's and/or connection's intended function.

On this basis, the project team found this enhancement acceptable because once enhancements are implemented, OCGS AMP B.1.35 will be consistent with GALL AMP XI.E2 and will provide additional assurance that the effects of aging will be adequately managed.

3.0.3.2.26.5 Operating Experience

In the OCGS LRA, the applicant stated that the cable testing and calibrations that are used for this program are performed currently, and have proven effective in identifying the existence of degradation in the performance of the system tested. OCGS has experienced failures of monitoring system cables and connectors that were identified during the conduct of routine testing. For example, a step change in the air ejector offgas radiation monitor readings was corrected by replacing the cables for both channels. When equipment cannot be brought into calibration, or when cable system tests indicate unacceptable results, evaluations are performed in accordance with the corrective action program, and appropriate actions are taken.

The project team reviewed the operating experience provided in the OCGS LRA and interviewed the applicant’s technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant’s technical staff, the project team determined that the applicant’s Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrument Circuits Program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.2.26.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrument Circuits Program in Section A.1.35 of Appendix A to the OCGS LRA, which states that the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrument Circuits Program is an existing program that manages aging of the cables of the IRM, LPRM/APRM, reactor building high-radiation monitoring, and air ejector offgas radiation monitoring systems that are sensitive instrumentation circuits with low-level signals, and are located in areas where the cables and connections could be exposed to adverse localized environments caused by heat, radiation, or moisture. These adverse localized environments can result in reduced insulation resistance, causing increases in leakage currents.

Calibration testing and current/voltage (I/V) and TDR testing are currently performed to ensure that the cable insulation resistance is adequate for the instrumentation circuits to perform their intended functions. Based on acceptance criteria related to instrumentation loop performance and cable testing set forth in the calibration and testing procedures, evaluation of unacceptable results is initiated under the corrective action program. The calibration testing and cable testing used for this program are performed currently, and have proven effective in identifying the existence of degradation in the performance of the tested systems. The program will be enhanced to include a review of the calibration and cable testing results for cable aging degradation, as recommended by Section XI.E2 of NUREG-1801. The enhanced program will be implemented before the period of extended operation and will include a review of the calibration and cable testing results for cable aging degradation before the period of extended operation and every 10 years thereafter.

The project team also reviewed the license renewal commitment list in Section A.5 of the OCGS LRA to confirm that the program enhancements will be implemented before the period of extended operation, and noted that it is Item 35 on the list of commitments.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.35, found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.2.26.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report are consistent with the GALL Report. In addition, the project team reviewed the enhancements and determined that their implementation before the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The project team also reviewed the UFSAR Supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.27 Metal Fatigue of Reactor Coolant Pressure Boundary (OCGS AMP B.3.1)

In the OCGS LRA, Appendix B, Section B.3.1, the applicant stated that OCGS AMP B.3.1, "Metal Fatigue of Reactor Coolant Pressure Boundary," is an existing plant program that is consistent with GALL AMP X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary,"(MFRCPB) with enhancements.

3.0.3.2.27.1 Program Description

The applicant stated, in the OCGS LRA, that this program provides for monitoring select components in the reactor coolant pressure boundary by tracking and evaluating key plant events. Events were selected based upon plant-specific evaluations of the most fatigue-limited locations for critical components, including those discussed in NUREG/CR-6260, ?Application of NUREG/CR-5999, Interim Fatigue Curves to Selected Nuclear Power Plant Components." The metal fatigue of reactor coolant pressure boundary program monitors operating transients to-date, calculates fatigue usage factors to-date, and permits implementation of corrective measures in order not to exceed the design limit on fatigue usage. The effects of reactor coolant environment will be considered through the evaluation of, as a minimum, those components selected in NUREG/CR-6260 using the appropriate environmental fatigue factors. The design basis metal fatigue analyses for the reactor coolant pressure boundary are considered TLAAs for license renewal. The program provides an analytical basis for confirming that the number of cycles established by the analysis of record will not be exceeded before the end of the period of extended operation. In order to determine cumulative usage factors (CUFs) more accurately, the program will implement FatiguePro fatigue monitoring software. FatiguePro® calculates cumulative fatigue using both cycle-based and stress-based monitoring. This provides an analytical basis for confirming that the number of cycles established by the analysis of record will not be exceeded before the end of the period of extended operation.

3.0.3.2.27.2 Consistency with the GALL Report

In the OCGS LRA, the applicant stated that OCGS AMP B.3.1 is consistent with GALL AMP X.M1, with enhancements.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.3.1, including PBD-AMP-B.3.01, ?Metal Fatigue of Reactor Coolant Pressure Boundary," Rev. 0, which provides an assessment of the AMP elements' consistency with GALL AMP X.M1. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.3.1 and associated bases documents to determine their consistency with GALL AMP X.M1.

In reviewing this program the project team noted that, on page 4-36 of the OCGS LRA, the applicant stated that the allowable cumulative fatigue usage factor (CUF) value is 1.0. The licensing basis for acceptable CUF for the reactor pressure vessel is currently stated in the Oyster Creek UFSAR to be 0.8. The applicant responded that OCGS is currently in the process of changing the CUF acceptance limit for the RPV to 1.0 using the approach described in 4.3.1 of the OCGS LRA. The applicant stated that, at the end of the audit review, the current licensing basis CUF limit for the RPV is changed to 1.0 in accordance with10 CFR 50.59. The applicant stated that AmerGen will revise the OCGS UFSAR to update the current licensing basis to reflect that a cumulative usage factor of 1.0 will be used in fatigue analyses for reactor coolant pressure boundary components, as endorsed by the NRC in 10 CFR 50.55a, before the period of extended operation as stated in a letter dated December 9, 2005, (ADAMS Accession Number ML053490219). The staff's TLAA review is discussed in Section 4 of the SER related to the OCGS LRA.

The applicant was asked to provide the backup documentation to support the fatigue analysis results and the associated design cycles for the isolation condensers. The project team confirmed that the applicant completed its fatigue analysis backup documentation.

The project team reviewed OCGS Power Operations Review Committee (PORC) meeting report (06-03) and specification OC-2006 E-001, ?Revised Method for Determination of Fatigue Cumulative Usage Factor," Revision 0. The project team noted that PORC approved the CUF limit change with some recommendations and conditions. The project team asked the applicant to clarify the methodology used for the determination of the Fatigue CUF. Also, the project team asked the applicant to clarify the original design intent to limit the CUF limit to 0.8 and whether the new design analysis and the revised fatigue analysis will be certified by a professional engineer with significant experience with ASME Code Section III fatigue analyses to demonstrate compliance to ASME Section III Class 1 analysis. In response, the applicant stated the following:

> From UFSAR section 5.3.1.1, the following statement provides the basis for the General Electric method of performing fatigue analysis for the Oyster Creek reactor vessel; ?For reactor pressure vessels designed and built prior to the adoption of the ASME Code Section III, the General Electric Company developed a method for performing a fatigue analysis which would provide assurance that vessels installed in General Electric designed nuclear power plants would safely withstand all anticipated operating and transient conditions, both normal and emergency conditions. This method was based upon the method of analysis developed for Naval reactors and upon industry's experience using it." The UFSAR also concludes that the General Electric Specification defined analysis results in a completed vessel for the Oyster Creek plant, which has safety margins that are generally equivalent to those which would result from using Section III methodology. General Electric's selection of a cumulative usage factor limit of 0.8 (versus 1.0) was to assure the Oyster Creek reactor pressure vessel design would remain bounded by the pending ASME Section III methodology and acceptance criterion.

There is no evidence that consideration was given to reserving margins for any other reason (e.g., for system transients or unspecified cyclic conditions not considered in original analysis). The reanalyzed fatigue usage factors were performed to the ASME Section III requirements to demonstrate acceptability to the corresponding acceptance limit of 1.0.

The Exelon 50.59 evaluations reviewed if using ASME Section III instead of the methods by GE to calculate fatigue usage represented a departure from a method of evaluation described in the UFSAR used in establishing design bases. The OC procedure for preparing 50.59 evaluations, based on NEI 96-07, provides the guidance that: Use of a new NRC-approved methodology (e.g., ASME Section III) to reduce uncertainty, provide more precise results, or other reason is not a departure from a method of evaluation described in the UFSAR, provided such use is (a) based on sound engineering practice, (b) appropriate for the intended application, and (c) within the limitations of the applicable SER. Oyster Creek is using the ASME Code Section III methodology to revise its design basis fatigue analyses for the reactor vessel; and the NRC has approved the use of ASME Code Section III via 10CFR50.55a, which is within the limitations of the Oyster Creek Licensing Basis. Therefore, implementing the ASME Code Section III method for analyzing fatigue is not considered a departure from a method of evaluation described in the UFSAR.

The licensing change allows Oyster Creek to revise design basis analysis from the methods described in GE specification 21A1105 to the NRC-approved methods of the ASME Code Section III. The licensing basis change provides Oyster Creek the ability to implement revised analysis to establish new allowable cycles [N(I)], using the methods described in ASME Code Section III. The difference in methodology is primarily associated with the difference between the s-N fatigue curve provided in the GE specification and the fatigue curve in the ASME Section III code. The process of summing transient pairs to determine total fatigue usage remains unchanged.

As part of the preparation of the Oyster Creek License Renewal application, limiting fatigue analyses of the reactor pressure vessel prepared per the original GE purchase specification for the RPV have been revised in accordance with the NRC approved ASME Code Section III as permitted by Appendix L of ASME Section XI. As stated in Appendix L the new fatigue usage values are compared to 1.0. This is not only a change in an acceptance limit but also a change in methodology, since fatigue usage factors were revised using the fatigue curve in ASME Section III instead of the fatigue curve provided in the GE specification. Oyster Creek has assumed the responsibility of the RPV design basis analysis in accordance with the Code requirements, and therefore, GE concurrence of the changes is not required nor was it requested.

Oyster Creek has revised the fatigue analysis for the limiting RPV locations in accordance with the methods established in NRC approved ASME Code Section III, as permitted by ASME Section XI IWB-3740. As stated in ASME XI Appendix L the revised usage factors are compared to 1.0. Since all of the revised usage factors are less than the acceptance limit, there are no adverse effects. The GE specification (21A1105) is still the current specification for the RPV. This specification will be updated to reflect the change in methodology as part the design change process.

As part of the effort for License Renewal, the current licensing basis RPV fatigue analysis was evaluated to demonstrate satisfactory results for the period of extended operation.

When the current licensing basis RPV fatigue analysis was reevaluated, using actual thermal cycles based on plant data, it was determined that for some locations the forty-year fatigue usage may exceed the 0.8 acceptance limit imposed by the GE spec. These locations required a more refined analysis. Under the rules of 10CFR50.55a and Section XI, Subsection IWB, the applicant is allowed to use Appendix L of Section XI to analyze the effects of fatigue on components. Appendix L directs that ASME Section III fatigue usage factor evaluation procedures be used to determine if they are acceptable for continued service. The fatigue usage factors for the reanalyzed components are less than 0.8 before environmental effects are included for License Renewal. However, there is no technical basis not to compare the usage factors to 1.0 since Appendix L establishes 1.0 as the appropriate acceptance limit. The revised analysis for the above components can be found in Exelon Design Analysis SIA No. OC-05Q-303 Revision 1.

The applicant stated that all supporting calculations and reports prepared by Structural Integrity Associates (SIA) for the fatigue activities associated with the Oyster Creek License Renewal Application were approved (and in many cases prepared) by a registered Professional Engineer. The registered Professional Engineer has significant experience with ASME Code Section III fatigue analyses, and is approved in accordance with SIA's Quality Assurance Program to be a qualified certifier of ASME Code, Section III, Division 1 Design Specifications and Design Reports. The approval of the Professional Engineer signifies acknowledgment that all documents are correct and complete to the best of his knowledge and that he or she is competent to approve the documents accordingly, and that all documents meet the intent of the pertinent sections of Section III, Subsection NB of the ASME Code (in accordance with the referenced Edition and Addenda) for Class 1 fatigue analysis. In its letter dated May 1, 2006, the applicant committed to certification by a Professional Engineer of the reactor vessel design specification and design reports prepared for the fatigue activities associated with the LRA. This will be performed by July 31, 2006. **This is Audit Commitment 3.0.3.2.27-1.**

The project team reviewed those portions of the metal fatigue of reactor coolant pressure boundary program for which the applicant claims consistency with GALL AMP X.M1 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's metal fatigue of reactor coolant pressure boundary program conforms to the recommended GALL AMP X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary," with the enhancements described below.

3.0.3.2.27.3 Exceptions to the GALL Report

None.

3.0.3.2.27.4 Enhancements

In the OCGS LRA, the applicant identified the following enhancement in order to meet the GALL Report program elements:

Elements: 3: Parameters Monitored/ Inspected
4: Detection of Aging Effects
5: Monitoring and Trending
6: Acceptance Criteria

Enhancement: The program will be enhanced to use the EPRI-licensed FatiguePro cycle counting and fatigue usage factor tracking computer program. The computer program provides for calculation of stress cycles and fatigue usage factors from operating cycles, automated counting of fatigue stress cycles and automated calculation and tracking of fatigue cumulative usage factors.

The program will provide for calculating and tracking of the cumulative usage factors for bounding locations for the reactor pressure vessel, Class I piping, the torus, torus vents, torus attached piping and penetrations, and the isolation condenser. The monitoring sample will include those locations where the predicted 40-year cumulative fatigue usage had been predicted to be 0.4 or greater, including the locations specified in NUREG/CR-6260, when applicable to Oyster Creek

The GALL Report identifies the following recommendations for the ?parameters monitored or inspected,” ?detection of aging effects,” ?monitoring and trending,” and acceptance criteria” program elements associated with the stated enhancement:

3. *Parameters Monitored or Inspected*: The program monitors all plant transients that cause cyclic strains, which are significant contributors to the fatigue usage factor. The number of plant transients that cause significant fatigue usage for each critical reactor coolant pressure boundary component is to be monitored. Alternatively, more detailed local monitoring of the plant transient may be used to compute the actual fatigue usage for each transient.

4. *Detection of Aging Effects*: The program provides for periodic update of the fatigue usage calculations.

5. *Monitoring and Trending*: The program monitors a sample of high fatigue usage locations. This sample is to include the locations identified in NUREG/CR-6260, as minimum, or propose alternatives based on plant configuration.

6. *Acceptance Criteria*: The acceptance criteria involves maintaining the fatigue usage below the design code limit considering environmental fatigue effects as described under the program description.

In reviewing this enhancement, the project team noted that, in the OCGS LRA, the applicant stated that the EPRI-licensed FatiguePro® computer program provides for calculation of stress cycles and fatigue usage factors from operating cycles, automated counting of fatigue stress cycles, and automated calculation and tracking of fatigue cumulative usage factors. The applicant also stated that the program will provide for calculating and tracking of the cumulative usage factors for bounding locations for the reactor pressure vessel, Class I piping, the torus, torus vents, torus attached piping and penetrations, and the isolation condenser. The monitoring sample will include those locations where the predicted 40-year cumulative fatigue usage had been predicted to be 0.4 or greater, including the locations specified in NUREG/CR-6260, when applicable to Oyster Creek.

During the audit and review, the project team evaluated the applicant's existing fatigue monitoring program and noted that it had correctly identified the need for more sophisticated methods to demonstrate adequate margin to fatigue limits. Improved calculation of environmental fatigue factors is also necessary. The project team determined that the use of FatiguePro® is an appropriate method to improve monitoring, and, taken together with the improved methodology for calculation of environmental fatigue factors, this enhancement provides assurance that fatigue damage will be adequately managed.

On this basis, the project team found this enhancement acceptable since when the enhancement is implemented, OCGS AMP B.3.1, "Metal Fatigue of Reactor Coolant Pressure Boundary," will be consistent with GALL AMP X.M1 and will provide additional assurance that the effects of aging will be adequately managed.

3.0.3.2.27.5 Operating Experience

The applicant stated, in the OCGS LRA, that Oyster Creek has reviewed both plant-specific operating experience relating to the metal fatigue of reactor coolant pressure boundary (MFRCPB) program. In instances where the potential existed to exceed CUFs before the end of plant life, the engineering analyses showed that actual margins were larger than initially estimated.

The applicant also stated that the MFRCPB program has been revised to incorporate changes in design basis analysis cycles to reflect reality. In response to NRC concerns that early-life operating cycles at some units had caused fatigue usage factors to increase at a greater rate than anticipated in the design analyses, the industry sponsored the development of the FatiguePro® computer program. The program is designed to ensure that the Code limits are not exceeded for the remainder of the licensed life, and provides for incorporation of operating experience.

The project team reviewed the operating experience provided in the OCGS LRA, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience. At OCGS, the fatigue evaluations confirm that significant margin remains to reach the CUF limit, and implementation of the proposed program will enable the applicant to prevent exceeding the limit.

On the basis of its review of the above plant-specific operating experience, and discussions with the applicant's technical staff, the project team determined that the applicant’s metal fatigue of reactor coolant pressure boundary program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

3.0.3.2.27.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the metal fatigue of reactor coolant pressure boundary program in OCGS LRA, Appendix A, Section A.3.1, which states that the metal fatigue of reactor coolant pressure boundary aging management program is an existing program that ensures that the design fatigue usage factor limit will not be exceeded during the period of extended operation. The program will be enhanced to calculate and track cumulative usage factors for bounding locations in the reactor coolant pressure boundary (reactor pressure vessel and Class I piping), containment torus, torus vents, and torus attached piping and penetrations. The program also tracks isolation condenser fatigue stress cycles.

The program will be enhanced to use the EPRI-licensed FatiguePro® cycle counting and fatigue usage factor tracking computer program, which provides for calculation of stress cycles and fatigue usage factors from operating cycles, automated counting of fatigue stress cycles, and automated calculation and tracking of fatigue cumulative usage factors. FatiguePro® calculates cumulative fatigue using both cycle-based and stress-based monitoring. The program will be enhanced prior to the period of extended operation."

The project team also reviewed the license renewal commitment list in Section A.5 of the OCGS LRA to confirm that this program will be enhanced to use the EPRI-licensed FatiguePro® cycle counting and fatigue usage factor tracking computer program prior to the period of extended operation, and noted that it is item 44 on the list of commitments.

In its letter dated May 1, 2006 (AmerGen Letter No. 2130-06-20328), the applicant committed to certification by a Professional Engineer of the reactor vessel design specification and design reports prepared for the fatigue activities. **This is Audit Commitment 3.0.3.2.27-1.**

The project team reviewed the UFSAR Supplement for OCGS AMP B.3.1. Contingent upon inclusion of audit commitment 3.0.3.2.27-1, the project team, found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

3.0.3.2.27.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report, are consistent with the GALL Report. Also, the project team has reviewed the enhancement and commitment 3.0.3.2.27-1 and determined that the implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The project team also reviewed the UFSAR Supplement for this AMP and found that, contingent upon the inclusion of audit commitment 3.0.3.2.27-1, it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3 *OCGS AMPs That Are Not Consistent with the GALL Report or Not Addressed in the GALL Report*

3.0.3.3.1 Periodic Testing of Containment Spray Nozzles (OCGS AMP B.2.1)

This AMP is assigned to the Office of Nuclear Reactor Regulation, Division of Engineering staff and will be addressed separately in Section 3.0.3.3 of the SER related to the OCGS LRA.

3.0.3.3.2 Lubricating Oil Monitoring Activities (OCGS AMP B.2.2)

This AMP is assigned to the Office of Nuclear Reactor Regulation, Division of Engineering staff and will be addressed separately in Section 3.0.3.3 of the SER related to the OCGS LRA.

3.0.3.3.3 Generator Stator Water Chemistry Activities (OCGS AMP B.2.3)

This AMP is assigned to the Office of Nuclear Reactor Regulation, Division of Engineering staff and will be addressed separately in Section 3.0.3.3 of the SER related to the OCGS LRA.

3.0.3.3.4 Periodic Inspection of Ventilation Systems (OCGS AMP B.2.4)

This AMP is assigned to the Office of Nuclear Reactor Regulation, Division of Engineering staff and will be addressed separately in Section 3.0.3.3 of the SER related to the OCGS LRA.

3.0.3.3.5 Periodic Inspection Program (OCGS AMP B.2.5)

This AMP is assigned to the Office of Nuclear Reactor Regulation, Division of Engineering staff and will be addressed separately in Section 3.0.3.3 of the SER related to the OCGS LRA.

3.0.3.3.6 Wooden Utility Pole Program (OCGS AMP B.2.6)

This AMP is assigned to the Office of Nuclear Reactor Regulation, Division of Engineering staff and will be addressed separately in Section 3.0.3.3 of the SER related to the OCGS LRA.

3.0.3.3.7 Periodic Monitoring of Combustion Turbine Power Plant (OCGS AMP B.2.7)

In response to RAI 2.5.1.19-1, which is documented in AmerGen letter 2130-05-20214 titled ?Response to NRC Request for Additional Information (RAI 2.5.1.19-1), dated September 28, 2005, Related to Oyster Creek Generating Station License Renewal Application (TAC No. MC7624)," dated October 12, 2005, the applicant stated that it had revised its approach to aging management for the Oyster Creek Station blackout system combustion turbine power plant. Specifically, AmerGen has taken a more detailed approach to scoping, screening, aging management reviews and AMPs. As a result, aging management program B.2.7, ?Periodic Monitoring of Combustion Turbine Power Plant," has been deleted. Therefore, the project team did not review this program.

3.1 OCGS LRA Section 3.1 – Aging Management of Reactor Vessel, Internals, and Reactor Coolant Systems

This section of the audit and review report documents the project team's review and evaluation of OCGS aging management review (AMR) results for the aging management of the reactor vessel, internals, and reactor coolant system components and component groups associated with the following systems: (1) isolation condenser system; (2) nuclear boiler instrumentation system; (3) reactor head cooling system; (4) reactor internals; (5) reactor pressure vessel; and (6) reactor recirculation system.

3.1.1 Summary of Technical Information in the Application

In the OCGS LRA Section 3.1, the applicant provided the results of its AMRs for the reactor vessel, internals, and reactor coolant system components and component groups.

In OCGS LRA Table 3.1.1, ?Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System," the applicant provided a summary comparison of its AMR line-items with the AMR line-items evaluated in the GALL Report for the reactor vessel, internals, and reactor coolant system components and component groups. The applicant also identified, for each component type in the OCGS LRA Table 3.1.1, those AMRs that are consistent with the GALL Report, those for which the GALL Report recommends further evaluation, and those AMRs that are not addressed in the OCGS LRA together with the basis for their exclusion.

In the OCGS LRA, Tables 3.1.2.1.1 through 3.1.2.1.6, the applicant provided a summary of the AMR results for component types associated with the (1) isolation condenser system; (2) nuclear boiler instrumentation system; (3) reactor head cooling system; (4) reactor internals; (5) reactor pressure vessel; and (6) reactor recirculation system. Specifically, the information for each component type included intended function, material, environment, aging effect requiring management, AMPs, the GALL Report Volume 2 item, cross reference to the OCGS LRA Table 3.1.1 (Table 1), and generic and plant-specific notes related to consistency with the GALL Report.

The applicant's AMRs incorporated applicable operating experience in the determination of aging effects requiring management (AERMs). These reviews included evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.1.2 Project Team Evaluation

The project team reviewed OCGS LRA Section 3.1 to determine if the applicant provided sufficient information to demonstrate that the effects of aging for the reactor vessel, internals, and reactor coolant system components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The project team reviewed certain identified AMR line-items to confirm the applicant's claim that these AMR line-items were consistent with the GALL Report. The project team did not repeat its review of the matters described in the GALL Report. However, the project team did verify that the material presented in the OCGS LRA was applicable and that the applicant had identified the appropriate GALL Report AMR line-items. The project team's audit evaluation is documented in Section 3.1.2.1 of this audit and review report. In addition, the project team's evaluations of the AMPs are documented in Section 3.0.3 of this audit and review report.

The project team reviewed those selected AMR line-items for which further evaluation is recommended by the GALL Report. The project team confirmed that the applicant's further evaluations were in accordance with the acceptance criteria in SRP-LR. The project team's audit evaluation is documented in Section 3.1.2.2 of this audit and review report.

The project team did not review the remaining AMR line-items that were not consistent with or not addressed in the GALL Report based on NRC-approved precedents. These AMRs were reviewed by NRR/DE staff and the results were documented in the SER related to the Oyster Creek plant.

Finally, the project team reviewed the AMP summary descriptions in the UFSAR Supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the reactor vessel, internals, and reactor coolant systems components.

Table 3.1-1 below provides a summary of the project team's evaluation of components, aging effects/aging mechanisms, and AMPs listed in LRA Section 3.1 that are addressed in the GALL Report. It also includes the section of the audit and review report in which the project team's evaluation is documented. It should be noted that the line items in this table correspond to the line items in Table 3.1-1 of the September 2005 Revision 1 SRP-LR document; therefore, in many cases, they do not match the line items in Table 3.1.1 of the OCGS LRA. The SRP-LR line item number is denoted parenthetically in the column 1 entry. Also, line items that are applicable only to PWR plants are not included in this table; therefore, certain SRP-LR line item numbers do not appear in this table.

Table 3.1-1 Project Team's Evaluation for LRA Section 3.1 – Reactor Vessel, Internals, and Reactor Coolant Systems Components in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Steel pressure vessel support skirt and attachment welds (Item 3.1.1-1)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	TLAAs were reviewed by NRR DE staff. (See Audit Report Section 3.1.2.2.1)
Steel; stainless steel; steel with nickel-alloy or stainless steel cladding; nickel-alloy reactor vessel components: flanges; nozzles; penetrations; safe ends; thermal sleeves; vessel shells, heads and welds (Item 3.1.1-2)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects are to be addressed for Class 1 components	TLAA BWR Feedwater Nozzle (B.1.5), BWR CRD Return Line Nozzle (B.1.6)	TLAAs were reviewed by NRR/DE staff. Acceptable-Crackin g due to fatigue for FW and CRDRL nozzle thermal sleeves will be managed in accordance with 10 CFR 54.21(c)(1)(iii). (See Audit Report Section 3.1.2.2.1)
Steel; stainless steel; steel with nickel-alloy or stainless steel cladding; nickel-alloy reactor coolant pressure boundary piping, piping components, and piping elements exposed to reactor coolant (Item 3.1.1-3)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects are to be addressed for Class 1 components	TLAA	TLAAs were reviewed by NRR/DE staff. (See Audit Report Section 3.1.2.2.1)
Steel pump and valve closure bolting (Item 3.1.1-4)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) check Code limits for allowable cycles (less than 7000 cycles) of thermal stress range	TLAA	TLAAs were reviewed by NRR/DE staff. (See Audit Report Section 3.1.2.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Stainless steel and nickel alloy reactor vessel internals components (Item 3.1.1-5)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA BWR Vessel Internals (B.1.9)	TLAAs were reviewed by NRR/DE staff Acceptable- Cracking due to fatigue will be managed in accordance with 10 CFR 54.21(c)(1)(iii). (See Audit Report Section 3.1.2.2.1)
Steel top head enclosure (without cladding) top head nozzles (vent, top head spray or RCIC, and spare) exposed to reactor coolant (Item 3.1.1-11)	Loss of material due to general, pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Not Applicable	Not Applicable since Oyster Creek top head enclosure is clad with stainless steel. (See Audit Report Section 3.1.2.2.2.1)
Steel and stainless steel isolation condenser components exposed to reactor coolant (Item 3.1.1-13)	Loss of material due to general (steel only), pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Water Chemistry (B.1.2) and an augmented inspection program to ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.1.1)	Acceptable- The augmented inspection program is equivalent to GALL's one-time inspection program and hence, consistent with GALL. (See Audit Report Section 3.1.2.2.2.2)
Stainless steel, nickel-alloy, and steel with nickel-alloy or stainless steel cladding reactor vessel flanges, nozzles, penetrations, safe ends, vessel shells, heads and welds (Item 3.1.1-14)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Water Chemistry and One-Time Inspection	Consistent with GALL, which recommends further evaluation. (See Audit Report Section 3.1.2.2.2.3)
Stainless steel; steel with nickel-alloy or stainless steel cladding; and nickel-alloy reactor	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Not Applicable	Not applicable since no GALL AMR line items related to this component group/ aging effect

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
coolant pressure boundary components exposed to reactor coolant (Item 3.1.1-15)				combination were credited in the OCGS LRA. (See Audit Report Section 3.1.2.2.2.3)
Steel (with or without stainless steel cladding) reactor vessel beltline shell, nozzles, and welds (Item 3.1.1-17)	Loss of fracture toughness due to neutron irradiation embrittlement	TLAA, evaluated in accordance with Appendix G of 10 CFR Part 50 and RG 1.99. Applicant may demonstrate that nozzle materials are not controlling for the TLAA evaluations.	TLAA, evaluated in accordance with Appendix G of 10 CFR Part 50 and RG 1.99.	TLAAs were reviewed by NRR/DE staff. (See Audit Report Section 3.1.2.2.3.1)
Steel (with or without stainless steel cladding) reactor vessel beltline shell, nozzles, and welds; safety injection nozzles (Item 3.1.1-18)	Loss of fracture toughness due to neutron irradiation embrittlement	Reactor Vessel Surveillance	Reactor Vessel Surveillance (B.1.23)	Consistent with GALL, which recommends further evaluation. AMP was reviewed by NRR/DE staff. (See Audit Report Section 3.1.2.2.3.2)
Stainless steel and nickel alloy top head enclosure vessel flange leak detection line (Item 3.1.1-19)	Cracking due to stress corrosion cracking and intergranular stress corrosion cracking	A plant-specific AMP is to be evaluated.	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.1.1)	Acceptable- ASME ISI program will adequately manage the aging effects; therefore, this is consistent with GALL. (See Audit Report Section 3.1.2.2.4.1)
Stainless steel isolation condenser components exposed to reactor coolant (Item 3.1.1-20)	Cracking due to stress corrosion cracking and intergranular stress corrosion cracking	Inservice Inspection (IWB, IWC, and IWD), Water Chemistry, and plant-specific verification program	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.1.1), Water Chemistry (B.1.2), and an augmented inspection program	Consistent with GALL, which recommends further evaluation. The augmented inspection program will verify that no cracking has occurred. (See Audit Report Section 3.1.2.2.4.2)
Stainless steel jet pump sensing line (Item 3.1.1-25)	Cracking due to cyclic loading	A plant-specific AMP is to be evaluated.	Not applicable	Not applicable, since Oyster Creek does not have jet pumps and jet pump sensing lines.

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
				(See Audit Report Section 3.1.2.2.8.1)
Steel and stainless steel isolation condenser components exposed to reactor coolant (Item 3.1.1-26)	Cracking due to cyclic loading	Inservice Inspection (IWB, IWC, and IWD) and plant-specific verification program	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.1.1), Water Chemistry (B.1.2), and an augmented inspection program	Consistent with GALL, which recommends further evaluation. The augmented inspection program will verify that no cracking has occurred. (See Audit Report Section 3.1.2.2.8.2)
Stainless steel steam dryers exposed to reactor coolant (Item 3.1.1-29)	Cracking due to flow-induced vibration	A plant-specific AMP is to be evaluated.	BWR Vessel Internals (B.1.9), with GE SIL-644, R1 recommendations as included in BWRVIP-139	Acceptable-Consistent with the current licensing basis and will adequately manage cracking; therefore, this is consistent with GALL. (See Audit Report Section 3.1.2.2.11)
Steel (with or without stainless steel cladding) control rod drive return line nozzles exposed to reactor coolant (Item 3.1.1-38)	Cracking due to cyclic loading	BWR CR Drive Return Line Nozzle	BWR CRD Return Line Nozzle (B.1.6) SS Thermal Sleeve by BWR Vessel Internals (B.1.9)	Consistent with GALL Acceptable (thermal sleeves). (See Audit Report Section 3.1.2.1)
Steel (with or without stainless steel cladding) feedwater nozzles exposed to reactor coolant (Item 3.1.1-39)	Cracking due to cyclic loading	BWR Feedwater Nozzle	BWR Feedwater Nozzle (B.1.5) Nickel Alloy Thermal Sleeves by BWR Vessel Internals (B.1.9)	Consistent with GALL. Acceptable (thermal sleeves). (See Audit Report Section 3.1.2.1)
Stainless steel and nickel alloy penetrations for control rod drive stub tubes instrumentation, jet pump instrumentation, standby liquid control, flux monitor, and drain line exposed to reactor coolant	Cracking due to stress corrosion cracking, Intergranular stress corrosion cracking, cyclic loading	BWR Penetrations and Water Chemistry	BWR Penetrations (B.1.8), Water Chemistry (B.1.2), and BWR Vessel Internals (B.1.9) ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.1.1), Water Chemistry (B.1.2)	Consistent with GALL. AMP B.1.9 provides additional assurance. (See Audit Report Section 3.1.2.1.6 and 3.1.2.1.7) Acceptable – CS & LAS Drain Nozzle Penetration. (See Audit Report Section 3.1.2.1.8)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
(Item 3.1.1-40)				
Stainless steel and nickel alloy piping, piping components, and piping elements greater than or equal to 4 NPS; nozzle safe ends and associated welds (Item 3.1.1-41)	Cracking due to stress corrosion cracking and intergranular stress corrosion cracking	BWR Stress Corrosion Cracking and Water Chemistry	BWR Stress Corrosion Cracking (B.1.7) and Water Chemistry (B.1.2)	Consistent with GALL. (See Audit Report Section 3.1.2.1)
Stainless steel and nickel alloy vessel shell attachment welds exposed to reactor coolant (Item 3.1.1-42)	Cracking due to stress corrosion cracking and intergranular stress corrosion cracking	BWR Vessel ID Attachment Welds and Water Chemistry	BWR Vessel ID Attachment Welds (B.1.4) and Water Chemistry (B.1.2)	Consistent with GALL. (See Audit Report Section 3.1.2.1)
Stainless steel fuel supports and control rod drive assemblies control rod drive housing exposed to reactor coolant (Item 3.1.1-43)	Cracking due to stress corrosion cracking and intergranular stress corrosion cracking	BWR Vessel Internals and Water Chemistry	BWR Vessel Internals (B.1.9) and Water Chemistry (B.1.2)	Consistent with GALL. (See Audit Report Section 3.1.2.1)
Stainless steel and nickel alloy core shroud, core plate, core plate bolts, support structure, top guide, core spray lines, spargers, jet pump assemblies, control rod drive housing, nuclear instrumentation guide tubes (Item 3.1.1-44)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking, irradiation-assisted stress corrosion cracking	BWR Vessel Internals and Water Chemistry	BWR Vessel Internals (B.1.9) and Water Chemistry (B.1.2)	Consistent with GALL. Enhanced inspections of cracked reactor components will be continued. (See Audit Report Sections 3.1.2.1.3, 3.1.2.1.4, and 3.1.2.1.5)
Steel piping, piping components, and piping elements exposed to reactor coolant (Item 3.1.1-45)	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.1.11)	Consistent with GALL. (See Audit Report Section 3.1.2.1)
Nickel alloy core shroud and core plate access hole cover (mechanical covers)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking,	Inservice Inspection (IWB, IWC, and IWD), and Water Chemistry	Not applicable	Not applicable, since Oyster Creek does not have access hole covers. (See Audit Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
(Item 3.1.1-46)	irradiation-assisted stress corrosion cracking			Section 3.1.2.3.1)
Stainless steel and nickel-alloy reactor vessel internals exposed to reactor coolant (Item 3.1.1-47)	Loss of material due to pitting and crevice corrosion	Inservice Inspection (IWB, IWC, and IWD), and Water Chemistry	BWR Vessel Internals (B.1.9)	Acceptable – The OCGS BWR vessel internals AMP is part of the OCGS ISI program. Also, all RVI components will be exposed to treated reactor water; therefore, the OCGS water chemistry AMP will be invoked. (See Audit Report Section 3.1.2.1.11)
Steel and stainless steel Class 1 piping, fittings and branch connections < NPS 4 exposed to reactor coolant (Item 3.1.1-48)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking (for stainless steel only), and thermal and mechanical loading	Inservice Inspection (IWB, IWC, and IWD), Water chemistry, and One-Time Inspection of ASME Code Class 1 Small-bore Piping	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.1.1), Water Chemistry (B.1.2), and One-Time Inspection (B.1.24).	Consistent with GALL. (See Audit Report Section 3.1.2.1.1 and 3.1.2.1.2)
Nickel alloy core shroud and core plate access hole cover (welded covers) (Item 3.1.1-49)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking, irradiation-assisted stress corrosion cracking	Inservice Inspection (IWB, IWC, and IWD), Water Chemistry, and, for BWRs with a crevice in the access hole covers, augmented inspection using UT or other demonstrated acceptable inspection of the access hole cover welds	Not applicable	Not applicable, since Oyster Creek does not have access hole covers. (See Audit Report Section 3.1.2.3.1)
High-strength low alloy steel top head closure studs and nuts exposed to air with reactor coolant leakage (Item 3.1.1-50)	Cracking due to stress corrosion cracking and intergranular stress corrosion cracking	Reactor Head Closure Studs	Reactor Head Closure Studs (B.1.3)	Consistent with GALL. (See Audit Report Section 3.1.2.1)
Cast austenitic stainless steel jet	Loss of fracture toughness due to	Thermal Aging and Neutron	Thermal Aging and Neutron Irradiation	Reviewed by DE. (See Audit Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
pump assembly castings; orificed fuel support (Item 3.1.1-51)	thermal aging and neutron irradiation embrittlement	Irradiation Embrittlement of CASS	Embrittlement of CASS (B.1.10)	Section 3.1.2.1)
Steel and stainless steel reactor coolant pressure boundary (RCPB) pump and valve closure bolting, manway and holding bolting, flange bolting, and closure bolting in high-pressure and high-temperature systems (Item 3.1.1-52)	Cracking due to stress corrosion cracking, loss of material due to wear, loss of preload due to thermal effects, gasket creep, and self-loosening	Bolting Integrity	Bolting Integrity (B.1.12)	Consistent with GALL. (See Audit Report Section 3.1.2.1)
Steel piping, piping components, and piping elements exposed to closed cycle cooling water (Item 3.1.1-53)	Loss of material due to general, pitting and crevice corrosion	Closed-Cycle Cooling Water System	Not applicable	Not applicable, since Oyster Creek has no such components within the scope of license renewal. (See Audit Report Section 3.1.2.3.1)
Copper alloy piping, piping components, and piping elements exposed to closed cycle cooling water (Item 3.1.1-54)	Loss of material due to pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	Not applicable	Not applicable, since Oyster Creek has no such components within the scope of license renewal. (See Audit Report Section 3.1.2.3.1)
Cast austenitic stainless steel Class 1 pump casings, and valve bodies and bonnets exposed to reactor coolant > 250°C (> 482°F) (Item 3.1.1-55)	Loss of fracture toughness due to thermal aging embrittlement	Inservice inspection (IWB, IWC, and IWD). Thermal aging susceptibility screening is not necessary, inservice inspection requirements are sufficient for managing these aging effects. ASME Code Case N-481 also provides an alternative for pump casings.	Inservice Inspection, Subsections IWB, IWC, and IWD (B.1.1). Thermal aging susceptibility screening is not necessary, inservice inspection requirements are sufficient for managing these aging effects. ASME Code Case N-481 also provides an alternative for pump casings	Consistent with GALL. (See Audit Report Section 3.1.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Copper alloy > 15% Zn piping, piping components, and piping elements exposed to closed cycle cooling water (Item 3.1.1-56)	Loss of material due to selective leaching	Selective Leaching of Materials	Not applicable	Not applicable, since Oyster Creek has no such components within the scope of license renewal. (See Audit Report Section 3.1.2.3.1)
Cast austenitic stainless steel Class 1 piping, piping component, and piping elements and control rod drive pressure housings exposed to reactor coolant > 250°C (> 482°F) (Item 3.1.1-57)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS	Thermal Aging and Neutron Irradiation Embrittlement of CASS (B.1.10) used for RVI components	Consistent with GALL (RVI components). (See Audit Report Section 3.1.2.1) For pump and valve bodies in ICS and RR systems – see Item 3.1.1-55 RHCS valve bodies are not identified for this aging effect since they are exposed to lower temperature.
Nickel alloy piping, piping components, and piping elements exposed to air – indoor uncontrolled (external) (Item 3.1.1-85)	None	None	None	Consistent with GALL. (See Audit Report Section 3.1.2.1)
Stainless steel piping, piping components, and piping elements exposed to air – indoor uncontrolled (External); air with borated water leakage; concrete; gas (Item 3.1.1-86)	None	None	None	Consistent with GALL. (See Audit Report Section 3.1.2.1)
Steel piping, piping components, and piping elements in concrete (Item 3.1.1-87)	None	None	Not applicable	Not applicable, since Oyster Creek has no such components in the RCSs within the scope of license renewal. (See Audit Report Section 3.1.2.3.1)

3.1.2.1 *AMR Results That Are Consistent with The GALL Report*

Summary of Information in the Application

For aging management evaluations that the applicant stated are consistent with the GALL Report, the project team conducted its audit and review to determine if the applicant's reference to the GALL Report in the OCGS LRA is acceptable.

In OCGS LRA Section 3.1.1.2.1, the applicant identified the materials, environments, and aging effects requiring management. The applicant identified the following programs that manage the aging effects related to the isolation condenser system; nuclear boiler instrumentation system; reactor head cooling system; reactor internals; reactor pressure vessel; and reactor recirculation system components and component groups:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.1.1)
- Water Chemistry (B.1.2)
- Reactor Head Closure Studs (B.1.3)
- BWR Vessel ID Attachment Welds (B.1.4)
- BWR Feedwater Nozzle (B.1.5)
- BWR CRD Return Line Nozzle (B.1.6)
- BWR SCC (B.1.7)
- BWR Penetrations (B.1.8)
- BWR Vessel Internals (B.1.9)
- Thermal Aging and Neutron Irradiation Embrittlement of CASS (B.1.10)
- Bolting Integrity (B.1.12)
- Reactor Vessel Surveillance (B.1.23)
- One-Time Inspection (B.1.24)
- Structures Monitoring Program (B.1.31)
- Lubricating Oil Monitoring Activities (B.2.2)

Project Team Evaluation

The project team reviewed its assigned OCGS LRA AMR line-items to determine that the applicant (1) provides a brief description of the system, components, materials, and environment; (2) states that the applicable aging effects have been reviewed and are evaluated in the GALL Report; and (3) identifies those aging effects for the isolation condenser system; nuclear boiler instrumentation system; reactor head cooling system; reactor internals; reactor pressure vessel; and reactor recirculation system components that are subject to an AMR.

3.1.2.1.1 Cracking Due to Thermal and Mechanical Loading in Class 1 Small Bore Piping

In the OCGS LRA, Section 3.1.2.2.12, the applicant provided its further evaluation to address cracking due to thermal and mechanical loading in Class 1 small-bore steel, steel with stainless steel cladding, and stainless steel reactor coolant system and connected system piping less than NPS 4, in accordance with the draft January 2005 SRP-LR.

In the OCGS LRA, Section 3.1.2.2.12, the applicant stated that Oyster Creek will use the ASME Section XI, inservice inspection, Subsections IWB, IWC, and IWD program (B.1.1) to mitigate cracking due to thermal and mechanical loading of steel and stainless steel piping, piping components, fittings and branch connections exposed to reactor coolant within the RCPB, including those components in core spray, the reactor recirculation, shutdown cooling, control rod drive, feedwater, main steam, standby liquid control, nuclear boiler instrumentation, post-accident sampling system, reactor head cooling system, reactor water cleanup, and isolation condenser systems. Oyster Creek will also use the One-Time Inspection Program (B.1.24) to verify that service-induced weld cracking is not occurring in the small-bore piping less than NPS 4, including pipe, fittings, and branch connections. LRA Section 3.1.2.2.12 further stated that observed conditions that have the potential for impacting the intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (AMP B.1.1), One-Time Inspection Program (AMP B.1.24) and verified that these programs are consistent with the recommendations in the GALL Report for AMPs XI.M1 and XI.M32, respectively. The project team determined that these programs would provide additional assurance that the aging effects are adequately managed; therefore, it is acceptable. On the basis of its review, the project team found that the applicant appropriately addressed cracking due to thermal and mechanical loading in Class 1 small-bore steel, steel with stainless steel cladding, and stainless steel reactor coolant system and connected system piping less than NPS 4.

3.1.2.1.2 <u>Cracking Due to Stress Corrosion Cracking and Intergranular Stress Corrosion Cracking</u>

3.1.2.1.2.1 <u>Cracking Due to Stress Corrosion Cracking and Intergranular Stress Corrosion Cracking [Item 1]</u>

In the OCGS LRA, Section 3.1.2.2.4.1, the applicant provided its further evaluation to address cracking due to SCC and IGSCC in Class 1 small-bore steel, steel with stainless steel cladding, and stainless steel reactor coolant system and connected system piping less than NPS 4, in accordance with the draft January 2005 SRP-LR.

In the OCGS LRA, Section 3.1.2.2.4.1, the applicant stated that Oyster Creek will use the Water Chemistry Program, B.1.2, to mitigate aging due to stress corrosion cracking and intergranular stress corrosion cracking of stainless steel piping, piping components, fittings and branch connection components exposed to reactor coolant within the RCPB, including those components in core spray, the reactor recirculation, shutdown cooling, control rod drive, feedwater, main steam, standby liquid control, nuclear boiler instrumentation, reactor head cooling system, reactor water cleanup, post-accident sampling, and isolation condenser systems. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program, B.1.1, will be used with the Water Chemistry Program to manage the effects of stress corrosion cracking. Oyster Creek will also use the One-Time Inspection Program, B.1.24, to verify that service-induced weld cracking is not occurring in small-bore piping less than NPS 4, including pipe, fittings, and branch connections. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD programs will also be used for Class 1 stainless steel pipe, piping components, fittings, and branch connections that are greater than or equal to NPS 4 to verify stress corrosion cracking is not occurring and to ensure the component intended function will be maintained during the extended period of operation. Observed conditions that have the potential for impacting the intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (AMP B.1.1), Water Chemistry Program (AMP B.1.2), and

One-Time Inspection Program (AMP B.1.24), and verified that these programs are consistent with the recommendations in the GALL Report for AMPs XI.M1, XI.M2,and XI.M32, respectively. The project team determined that these programs would provide additional assurance that the aging effects are adequately managed; therefore, it is acceptable. On the basis of its review, the project team found that the applicant appropriately addressed cracking due to SCC and IGSCC in Class 1 small-bore steel, steel with stainless steel cladding, and stainless steel reactor coolant system and connected system piping less than NPS 4.

3.1.2.1.2.2 Cracking Due to Stress Corrosion Cracking and Intergranular Stress Corrosion Cracking [Item 2]

In the OCGS LRA, Table 3.1.2.1.1 for the isolation condenser system, Table 3.1.2.1.2 for the nuclear boiler instrumentation, and Table 3.1.2.1.6 for the reactor recirculation system include AMR line items for cracking due to SCC and IGSCC of stainless steel piping and fittings exposed to treated water or steam (internal). The applicant proposed to manage this aging effect using the OCGS BWR stress corrosion cracking program (AMP B.1.7), the Water Chemistry Program (AMP B.1.2), and the ASME Section XI ISI, Subsections IWB, IWC, and IWD program (AMP B.1.1). Generic note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report; however, a different aging management program was credited. The GALL Report recommended the BWR stress corrosion cracking program (AMP XI.M7) and the Water Chemistry Program (AMP XI.M2). Plant specific notes were also included in the OCGS LRA indicating that the ASME Section XI ISI program was included in addition to the programs recommended by GALL.

The project team reviewed the applicant's BWR stress corrosion cracking program (AMP B.1.7) and Water Chemistry Program (AMP B.1.2), and verified that these programs are consistent with the recommendations in the GALL Report for AMPs XI.M7 and XI.M2, respectively. The project team determined that the addition of the ASME Section XI ISI program (AMP B.1.1) would provide additional assurance that the aging effects are adequately managed; therefore, it is acceptable.

On the basis of its review, the project team found that the applicant appropriately addressed cracking due to SCC and IGSCC for stainless steel piping and fittings exposed to treated water in the reactor vessel, internals, and reactor coolant systems.

3.1.2.1.2.3 Cracking Due to Stress Corrosion Cracking and Intergranular Stress Corrosion Cracking [Item 3]

In the OCGS LRA, Table 3.1.2.1.5 for the reactor pressure vessel includes AMR line items for cracking due to SCC and IGSCC of stainless steel CRD stub tube penetrations exposed to treated water. The applicant proposed to manage this aging effect using the OCGS BWR vessel internals program (AMP B.1.9) and the Water Chemistry Program (AMP B.1.2). Generic note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report; however, a different aging management program was credited. The GALL Report recommended the BWR penetrations program (AMP XI.M8) and the Water Chemistry Program (AMP XI.M2). Plant specific notes were also included in the OCGS LRA indicating that the OCGS BWR penetrations program does not address CRD stub tubes; which are addressed in the OCGS BWR vessel internals program.

The project team reviewed the applicant's evaluation and determined that the BWR vessel internals program (AMP B.1.7) is appropriate to address the CRD stub tubes. This AMP was reviewed for technical adequacy by the NRR/DE staff, and their evaluation is documented in the SER related to the OCGS LRA. The project team also reviewed the OCGS Water Chemistry Program (AMP B.1.2), and verified that it is consistent with the recommendations in the GALL Report for AMP XI.M2. The project team determined that the programs credited to manage cracking of he CRD stub tubes are appropriate.

On the basis of its review, the project team found that the applicant appropriately addressed cracking due to SCC and IGSCC for stainless steel CRD stub tubes exposed to treated water in the reactor vessel, internals, and reactor coolant systems.

3.1.2.1.3 Cracking Due to IASCC of Top Guide

In the OCGS LRA, Table 3.1.2.1.4 for the reactor internals, the applicant credits BWR vessel internals (B.1.9) and water chemistry (B.1.2) aging management program to manage cracking due to SCC, IGSCC and IASCC in stainless steel and nickel alloy core shroud, core plate, core plate bolts, support structure, top guide, core spray lines, spargers, jet pump assemblies, control rod drive housing, nuclear instrumentation guide tubes.

During the audit and review, the project team noted that several NRC INs, including IN 95-17, addressed cracking of BWR top guides within the operating experience of domestic and foreign reactors. The top guide at Oyster Creek has experienced problems with cracking since the early nineties. Therefore, the applicant was asked to describe how cracking of the top guide will be managed by the BWR vessel internals and water chemistry AMPs, as stated in LRA Table 3.1.2.1.4, during the period of extended operation. In its response, the applicant stated that during the 13R refueling outage in 1991, Oyster Creek found a crack on the underside of a top guide beam. During the 14R and 15R refueling outages in 1992 and 1994, additional cracks were discovered on the underside of top guide beams. As a result of these findings, UT inspections were performed for the complete top guide during the 16R refueling outage in 1996. This comprehensive inspection identified 5 mid-span cracks and 12 UT indications in the notches used to interlock the beams. The majority of the cracks and indications were located in the NE quadrant of the top guide. Additionally, a sample of the top guide was removed for metallurgical examination during the 16R refueling outage and the aging mechanism was determined to be irradiation-assisted stress corrosion cracking (IASCC). Furthermore, a flaw growth evaluation was prepared for the most significant crack to predict future crack growth and to evaluate its effects upon structural integrity of the top guide. The flaw evaluation predicted a maximum crack growth of 1.6 inches within two cycles of operation and determined that even if this occurred, the structural integrity of the top guide would not be compromised.

The applicant also stated that visual inspections of the top guide were performed again during the 18R refueling outage in 2000. The visual inspection of the limiting flaw determined that it had grown approximately half of the maximum predicted crack growth value during the two operating cycles since the previous inspection. The crack was still well within evaluated limits and did not impair the structural integrity of the top guide. Additional visual inspections were made during the 20R refueling outage in 2004 to monitor crack growth. These inspections indicated that there was no additional crack growth during the previous two operating cycles.

The applicant further stated that it is currently planning to inspect the top guide during the next refueling outage using UT examination. As a minimum, the complete NE quadrant of the top guide will be inspected to determine if the cracking has been mitigated. If significant crack growth is identified in the NE quadrant, additional inspections will be performed as necessary to characterize crack growth. As discussed in BWRVIP-26-A, Oyster Creek is a lead plant with respect to top guide cracking due to its age and top guide fluence and all inspections will be performed in accordance with BWRVIP-26-A. Therefore, the results of the 2006 inspections will provide key information in developing top guide inspection guidelines, and the frequency and scope of future inspections may be adjusted based on these inspection results. This program provides assurance that the top guide will perform its intended functions during the period of extended operation.

As stated in the September 2005 GALL Report, item IV.B1.17 ®-98), for top guides with neutron fluence exceeding the IASCC threshold prior to the period of extended operation, the applicant will inspect 10% of the top guide locations using enhanced visual inspection technique, EVT-1, within 12 years, with one-half of the inspections (i.e., 5% of locations) to be completed within 6 years after entering the period of extended operation. The applicant stated that corrective actions will be taken, including repair or replacement of the top guide, if found necessary. This is consistent with the GALL recommendations (commitment 9).

On the basis of its review, the project team found that the applicant appropriately addressed the aging effect/mechanism, as recommended by the GALL Report.

3.1.2.1.4 Cracking Due to IASCC of Core Shroud

In the OCGS LRA, Table 3.1.2.1.4 for the reactor internals credits the BWR vessel internals (B.1.9) and water chemistry (B.1.2) AMPs to manage cracking due to SCC, IGSCC and IASCC in stainless steel and nickel alloy core shroud, core plate, core plate bolts, support structure, top guide, core spray lines, spargers, jet pump assemblies, control rod drive housing, nuclear instrumentation guide tubes.

During the audit, the project team noted that a review of industry experience has confirmed that cracking has been observed in core shrouds at both horizontal (NRC GL 94 03) and vertical (NRC IN 97-17) welds. The core shroud at Oyster Creek has cracked and has been operating in its repaired configuration. In light of this, the applicant was asked to describe how continued aging of the cracked core shroud and its repair hardware will be managed by the BWR vessel internals and water chemistry AMPs, as stated in LRA Table 3.1.2.1.4, during the period of extended operation. In its response, the applicant stated that cracking has affected shrouds fabricated from Type 304 and Type 304L stainless steel. In 1994 Oyster Creek performed a comprehensive examination of the shroud and discovered significant cracking in the core shroud H4 circumferential weld. Additional minor cracking was found in the H2 and H6 welds. The examinations consisted of visual examinations with cleaning and UT examinations wherever practical. During the same refueling outage, shroud repair hardware was installed to ensure the shroud could continue to perform its intended function. The repair consisted of 10 tie rods anchored at the top and bottom of the shroud. Details of the repair design were sent to the NRC in 1994. The shroud repair system structurally replaces all horizontal welds. Therefore, as discussed BWRVIP-76, no further inspection of the horizontal welds is required. Subsequent inspections focused on the vertical welds.

The applicant also stated that subsequent inspections of the repair hardware have confirmed that the tie rods are in good condition and continue to provide reliable structural support for the shroud. Following the guidelines of BWRVIP-76, Oyster Creek has chosen to implement the option to inspect all vertical welds. The accessible length of all vertical welds was inspected in 1998 and 2000. All inspected welds were found free of indications, except that the V-9 weld indicated a small flaw (less than 2”), which was acceptable using the acceptance criteria of BWRVIP-76.

The applicant further stated that Oyster Creek will complete inspection of all vertical welds in accordance with BWRVIP-76 guidelines by 2008. Currently, the vertical welds are scheduled to be inspected using UT techniques in 2006.

For the period of extended operation, the applicant stated that the inspections identified above will be continued in accordance with BWRVIP-76 guidelines. All vertical welds will be inspected every ten years using either EVT-1 or UT examination methods. Repair assemblies will be inspected using VT-3 of locking devices, critical gap or contact areas, bolting and the overall component. The repair anchorage inspections include an EVT-1 inspection of the most highly stressed accessible load bearing weld every 10 years. If indications are identified, they will be evaluated and appropriate corrective actions will be taken.

The project team reviewed the current status of the repaired hardware and the overall structural integrity of the shroud. No particular degradation was noted since the shroud was repaired. The applicant is performing augmented inspections of the shroud as well as the repaired hardware following the BWRVIP recommendations.

On the basis of its review, the project team found that the applicant appropriately addressed the aging effect/mechanism.

3.1.2.1.5 Cracking Due to SCC, IGSCC, AND IASCC of Core Spray Spargers

In the OCGS LRA, Table 3.1.2.1.4 for reactor internals, the applicant credits the BWR vessel internals (B.1.9) and water chemistry (B.1.2) AMPs to manage cracking due to SCC, IGSCC and IASCC in stainless steel and nickel alloy core shroud, core plate, core plate bolts, support structure, top guide, core spray lines, spargers, jet pump assemblies, control rod drive housing, nuclear instrumentation guide tubes.

During the audit, the project team noted that instances of cracking in BWR core spray spargers have been reviewed in NRC Bulletin 80-13. Core spray spargers at Oyster Creek have experienced cracking since the late seventies. In light of this, the applicant was asked to describe how the continued aging of the cracked core spray spargers and their repair hardware will be managed by the BWR vessel internals and water chemistry AMPs, as stated in LRA Table 3.1.2.1.4, during the period of extended operation. In its response, the applicant stated that Oyster Creek identified crack indications in the core spray spargers in 1978. One mechanical clamp was installed during that refueling outage to provide structural support for a crack identified in one of the core spray spargers. The installed clamp ensures long-term structural integrity of the sparger, but no credit is taken as a leakage limiter. In 1980, additional linear indications were reported. As a result of the indications, nine additional mechanical clamps were installed. All four tee boxes on both spargers were clamped. The primary root cause of the cracking problems identified in 1978 and 1980 was reported to be high residual stresses from forcing the sparger pipes into position during installation. Consistent with this root cause, the cracking was expected to relieve the residual stresses and stop any further growth, as well as the initiation of new cracks. No further cracking or other degradation of the spargers has been reported since 1980.

The applicant also stated that recent inspections in 1998, 2000, 2002, and 2004 have confirmed that the repair clamps are in good condition. Inspection of the core spray piping welds has confirmed that the mitigation efforts provided by the reactor water chemistry program have been successful, as no new crack indications have been found. The core spray piping and spargers inside the reactor vessel at Oyster Creek are inspected in accordance with BWRVIP-18-A, which specifies inspection of core spray internals, including piping, spargers, nozzles, and brackets. There are no ASME Section XI requirements for the Core spray internals. As prescribed by BWRVIP-18-A, during each refueling outage, the following components are evaluated using EVT-1 enhanced visual examination methods: accessible core spray piping fillet welds; 25% of the core spray piping brackets; 25% of the core spray piping butt welds; end cap welds; and T-box cover plate welds. The following components are examined using VT-1 visual examination methods during each refueling outage: nozzle-to-pipe welds, nozzle-to-orifice welds, sparger brackets, and repair clamps.

For the period of extended operation, the applicant stated that inspections identified above will be continued in accordance with BWRVIP-18-A guidelines. If indications are identified, they will be evaluated and appropriate corrective actions will be taken.

The project team reviewed the current status of the repaired hardware and the overall structural integrity of the core spray piping and spargers. No particular degradation was noted since the core spray spargers were repaired. The applicant is performing augmented inspections of the core spray piping and the repaired hardware following the BWRVIP recommendations accepted by the staff. On this basis, the project team found that the applicant is adequately managing aging of the core spray spargers.

On the basis of its review, the project team found that the applicant appropriately addressed the aging effect/mechanism.

3.1.2.1.6 Cracking Due to SCC of CRD Stub Tubes

In the OCGS LRA, Table 3.1.2.1.5 for the reactor pressure vessel, the applicant credits the BWR penetrations (B.1.8), BWR Vessel internals (B.1.9) and water chemistry (B.1.2) AMPs to manage cracking due to SCC, IGSCC, and cyclic loading in stainless steel and nickel alloy penetrations for control rod drive stub tubes instrumentation, jet pump instrumentation, standby liquid control, flux monitor, and drain line exposed to reactor coolant.

During the audit, the project team noted that several CRD stub tubes at OCGS have been leaking recently, and roll expansion repairs were performed to limit this leakage. In light of this, the applicant was asked to describe how the continued aging of the leaking CRD stub tubes and their repairs will be managed by the BWR penetrations, BWR vessel internals and water chemistry AMPs, as stated in LRA Table 3.1.2.1.5, during the period of extended operation. In its response, the applicant stated that during the 1974 4R refueling outage, one spare incore housing was repaired at location 28-05 by roll expansion. During the 18R refueling outage in 2000, while performing the RPV pressure test, leakage was observed from CRD housing locations 42-43 and 46-39 at the bottom head interface. The stub tube welds to these CRD housings were found to be cracked and leaking. A roll expansion repair design was engineered in accordance with BWRVIP-17. UT inspections were performed inside the CRD housings where they meet the bottom head and also in the bore area of the upper J weld between the CRD housings and the top of the stub tubes. No indications were identified in any of these locations. CRD Housing locations 42-43 and 46-39 were roll expansion repaired and the leakage was stopped. A post-repair UT inspection was performed to verify that the rolling did not damage the CRD housing material. No indications were found in the roll expansion repair area of either core location.

The applicant also stated that the spare incore housing that had been roll expansion repaired in 1974 was last inspected in 1983 and no further indication of degradation was found. No signs of leakage have been identified for this repaired incore housing since the roll repair was performed. This showed the effectiveness of the roll expansion repair method. During the 19R refueling outage in 2002, the two CRD stub tube penetrations that had been roll expansion repaired in 2000 were reinspected by removing one control rod guide tube to allow access to the lower plenum area of the RPV. No cracking were identified. No under vessel leakage was observed from these locations. These inspections demonstrated that the roll expansion repairs have been effective in sealing the penetrations and preventing leakage.

The applicant further stated that BWRVIP-47 indicates that inspection of the stub tubes and CRD housings is not required. However, BWRVIP-17 specifies in-service inspection recommendations for all roll-expanded CRD housings. ASME Section XI specifies inspection requirements for the reactor vessel pressure boundary. A VT-2 visual examination is performed during the RPV pressure test to satisfy the requirements of ASME Section XI. The examinations are performed at the nominal operating pressure of the Class 1 pressure boundary. Due to the stub tube leakage in the bottom head identified in 2000, Oyster Creek has committed to perform inspections for leakage whenever the drywell is made accessible during outages. Currently a minimal amount of leakage is permitted for rolled repaired housing. This leakage allowance is valid only through the next refueling outage (2006). If the ASME Code Case N-730 on roll expansion repair is approved and adopted at Oyster Creek, then weld repairs will be made for leaking stub tubes that cannot be made leak tight using a roll repair prior to restarting the plant.

The applicant also stated that Oyster Creek is pursuing Code Case N-730 within ASME to make these roll expansion repairs permanent. Once the ASME and NRC approve the Code Case, the Oyster Creek BWR reactor internals program will be revised to make these repairs permanent. If Code Case N-730 is not approved, the program will be changed to require weld repair for the previously roll expansion repaired components prior to the period of extended operation.

The applicant stated that the current program will be continued during the period of extended operation in accordance with the requirements of the approved Code Case N-730. If Code Case N-730 is not approved, the current program will be continued except any leaking components will be weld repaired. Inspections for leakage will be performed in accordance with the requirements of the Code Case. VT-2 visual examinations will be performed during the RPV pressure test to satisfy the requirements of ASME Section XI. If leakage is detected on a CRD housing, the leakage will be stopped using a roll expansion repair, provided the Code Case is approved at the time. If leakage from a stub tube can not be stopped with an approved roll repair, a weld repair will be made prior to plant restart. If the Code Case is not approved, an ASME and NRC approved weld repair will be made. UT examinations of roll repaired CRD housings bore will be made in accordance with the requirements of the Code Case.

The project team reviewed the current status of the stub tubes and their repair, and the overall structural integrity of the vessel bottom head. No degradation was noted since the stub tubes were repaired. The applicant is performing augmented inspections of these stub tubes following the BWRVIP recommendations accepted by the staff.

In its letter dated April 18, 2006, in response to the staff's RAI B1.9-3 (ML061100138), the applicant committed to revise LRA Section B.1.9 to clarify its position related to the use of roll/expansion techniques for the repair of leaking CRD stub tubes which will result in no leakage of the CRD of the stub tubes during the extended period of operation as follows:

> If Code Case N-730 is not approved, Oyster Creek will develop a permanent ASME code repair plan. This permanent ASME code repair could be performed in accordance with

BWRVIP-5:3-A, which has been approved by the NRC, or an alternate ASME code repair plan which would be submitted for prior NRC approval. If it is determined that the repair plan needs prior NRC approval, Oyster Creek will submit the repair plan two years before entering the period of extended operation. After the implementation of an approved permanent roll repair (draft Code Case N-730), if there is a leak in a CRD stub tube, Oyster Creek will weld repair any leaking CRD stub tubes during the extended period of operation by implementing a permanent NRC approved ASME Code repair for leaking stub tubes that cannot be made leak tight using a roll expansion method prior to restarting the plant. Appendix A.1.9 and item number 9 of Table A.5 Commitment List will be updated to reflect the above commitments. This is **Audit Commitment 3.1.2.1.6-1.**

On this basis, the project team found that the applicant is adequately managing aging of the CRD stub tubes.

On the basis of its review, the project team found that the applicant appropriately addressed the aging effect/mechanism based on the commitment.

3.1.2.1.7 Cracking Due to IASCC of In-Core Neutron Monitor Dry Tubes

In the OCGS LRA, Table 3.1.2.1.4 for the reactor internals, the applicant credits the BWR penetrations (B.1.8), BWR vessel internals (B.1.9) and water chemistry (B.1.2) AMPs to manage cracking due to SCC, IGSCC, and cyclic loading in stainless steel and nickel alloy penetrations for control rod drive stub tubes instrumentation, jet pump instrumentation, standby liquid control, flux monitor, and drain line exposed to reactor coolant.

During the audit, the project team noted that several reactor vessel in-core neutron monitor dry tubes at Oyster Creek have cracked and been replaced. In light of this, the applicant was asked to describe how the continued aging of the cracked in-core neutron monitor dry tubes will be managed by the BWR vessel internals and water chemistry AMPs, as stated in LRA Table 3.1.2.1.4, during the period of extended operation. In its response, the applicant stated that in 1984 cracking was identified on 8 of the 12 original in-core dry tubes at OCGS. The cracking was found in the non-pressure retaining plunger shaft area and was determined to have been caused by IGSCC as the result of a crevice condition associated with the original dry tube design. In 1984, two of the 12 dry tubes were replaced with a new crevice-free single piece plunger shaft design. The other 6 cracked tubes were technically justified as acceptable for one additional operating cycle. In 1986, the remaining 10 dry tubes were replaced so that all of dry tubes in service have the same crevice-free single piece plunger shaft design.

The applicant also stated that in 1988, all dry tubes were inspected and no cracking was identified. IRM-17 was replaced due to a bent tip. In 1991 and 1992, all dry tubes were visually examined with no findings. In 1994, four dry tubes were visually examined with no findings. In 1996, IRM-15 was visually examined with no findings. In 1998, IRM-15 was examined with no findings. In 2000, five dry tubes were visually examined to VT-1 standards. No cracking was identified, but one tip was slightly bent. In 2004, three dry tubes were examined with no findings. These inspection results demonstrate that the replacement design has been effective in preventing cracking due to IGSCC.

The applicant further stated that the inspection plan requires inspections to be conducted on the in-core dry tubes in accordance with the requirements of GE SIL-409, Revision 2 and BWRVIP-47. BWRVIP-47 describes the inspection recommendations for the lower plenum region of the vessel. BWRVIP-47 indicates that inspection of the in-core housing and dry tubes are not required, due to the good field history, significant operating experience, and minimal safety significance. Regardless, at Oyster Creek, the inspections of the in-core dry tubes are performed consistent with the recommendations of GE SIL-409, Revision 2, which recommends replacement after 20 years of service. This is due to the high neutron flux where these components are located, which increases the potential for cracking due to IASCC after long periods of service. Therefore, six of the dry tubes are scheduled for replacement in 2006 and the remaining six are scheduled for replacement in 2008.

During the period of extended operation, the applicant stated that Oyster Creek will continue to follow the guidance of GE SIL-409, including periodic visual examinations. This, in combination with the replacement of the entire set of dry tubes with new ones of the improved design, provides assurance that the dry tubes will continue to perform their intended function through the period of extended operation.

The project team reviewed the current status of the in-core neutron monitor dry tubes. The applicant is going to replace these tubes as recommended in the BWRVIP recommendations and accepted by the staff. On this basis, the project team found that the applicant is adequately managing aging of the in-core neutron monitor dry tubes.

On the basis of its review, the project team found that the applicant appropriately addressed the aging effect/mechanism.

3.1.2.1.8 Cracking Due to SCC, IGSCC, and Cyclic Loading of Vessel Drain Nozzle

In the OCGS LRA, Table 3.1.2.1.5 for the reactor pressure vessel, the applicant credits the BWR penetrations (B.1.8), BWR vessel internals (B.1.9) and water chemistry (B.1.2) AMPs to manage cracking due to SCC, IGSCC, and cyclic loading in stainless steel and nickel alloy penetrations for control rod drive stub tubes instrumentation, jet pump instrumentation, standby liquid control, flux monitor, and drain line exposed to reactor coolant.

During the audit, the project team noted that, in the OCGS LRA, Table 3.1.1, line item 31 did not include the vessel drain nozzle penetration. The applicant was asked to explain why this nozzle penetration is not included since all other vessel nozzles are addressed in this line item. In its response, the applicant stated that the bottom head nozzle is a two-inch partial weld penetration that is made of carbon steel and is, therefore, not included with the stainless steel and nickel alloy penetrations in LRA Table 3.1.1-31. However, the aging management of this bottom head drain nozzle is included in LRA Table 3.1.2.1.5 for the reactor pressure vessel. The project team verified this and found that ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.1.1) and water chemistry (B.1.2) AMPs are appropriately credited for managing cracking of the vessel drain nozzle.

On the basis of its review, the project team found that the applicant appropriately addressed the aging effect/mechanism.

3.1.2.1.9 Cracking Due to SCC, IGSCC, and Cyclic Loading of Valve Bodies

During the audit and review, the project team noted that OCGS LRA Table 3.1.2.1.3 for the reactor head cooling system includes line items for restricting orifice and valve bodies, and cracking of these components is managed by the water chemistry and one-time inspection AMPs. Plant specific note 5 to this table stated that ASME Section XI ISI, Subsections IWB, IWC, and IWD, does not apply to these components. The applicant was asked to clarify why ASME Section XI ISI, Subsections IWB, IWC, and IWD, does not apply to valves. Also, the applicant was asked to provide the technical basis for concluding that the water chemistry and one-time inspection programs alone, without periodic inspections, will adequately manage cracking of these components during the period of extended operation.

In its response, the applicant stated that ASME Section XI ISI, Subsections IWB, IWC, and IWD does apply to valves, but not for mitigation of cracking, except for the Electromatic Relief Valves (EMRVs) in the main steam system. In line items R-03 and R-55 (subsequently deleted from the September 2005 Revision 1 to GALL) which address cracking in piping, GALL does not credit ASME Section XI ISI, Subsections IWB, IWC, and IWD for managing cracking in valves. In the ISI program, only Category B-1, which requires UT testing of welds in valve bodies, could detect cracks in valve bodies. At Oyster Creek, this is applied only to the EMRVs in the main steam system. ISI inspection of valves per B-2 is by VT-3, which visually inspects for corrosion, wear, or erosion, but is not credited for crack detection.

The applicant also stated that ISI addresses the welds (including the weld between pipe and valve body) and BWRSCC addresses cracking in the heat affected zone. The ISI program is not credited for crack mitigation in valves (except for the EMRVs in main steam as discussed above, which is specifically addressed in the OC ISI program plan).

The applicant further stated that January 2005 draft GALL line item R-55 stated that AMPs for managing cracking are to be augmented to verify that cracking is not occurring, and stated that one-time inspection is an acceptable verification method. The one-time inspection aging management program is used to verify the system-wide effectiveness of AMPs such as water chemistry that are designed to prevent or minimize aging to the extent that it will not cause a loss of intended function during the period of extended operation. The program provides inspections that either verify that unacceptable degradation is not occurring or that trigger additional actions that will assure the intended function of affected components will be maintained during the period of extended operation. The one-time inspection aging management program is used to confirm the effectiveness of the water chemistry program to manage crack initiation and growth aging effects during the period of extended operation.

The project team found that small valve bodies do not have any welds to be inspected using the inservice inspection program, except the welds at the piping connection locations, which are routinely inspected by the plant ISI program. Also, the explanation provided for using one-time inspection to verify the effectiveness of Water Chemistry Program is consistent with GALL Report recommendation.

On the basis of its review, the project team found that the applicant appropriately addressed the aging effect/mechanism.

3.1.2.1.10 Loss of Material Due to General Corrosion of External Surface or Carbon and Low Alloy Steel Components

In OCGS LRA Table 3.1.2.1.1 for the isolation condenser system, Table 3.1.2.1.3 for the reactor head cooling system, and Table 3.1.2.1.6 for the reactor recirculation system, the applicant proposed to manage loss of material for the external surfaces of carbon and low alloy steel components exposed to an air environment using the structures monitoring program (AMP B.1.31). However, the project team noted that the GALL Report recommends the external surfaces monitoring aging management program (AMP XI.M36) to manage this aging effect.

The project team evaluated the applicant's use of the structures monitoring program (AMP B.1.31) as a substitute for GALL AMP XI.M36 to manage this aging effect, and found it acceptable. The project team's evaluation is documented in Section 3.3.2.1.6.3 of this audit and review report.

3.1.2.1.11 Loss of Material Due to Pitting and Crevice Corrosion in Stainless Steel and Nickel-Alloy Reactor Vessel Internals Components

The project team noted that the applicant did not credit the GALL Report AMR for loss of material due to pitting and crevice corrosion in stainless steel and nickel-alloy reactor vessel internals components exposed to reactor water, which is associated with Table 1, item 3.1.1-47 in the GALL Report. This was a new AMR that was not in the draft January 2005 GALL Report.

In Attachment 7, Item RP-26, of its reconciliation document, the applicant stated that loss of material due to pitting and crevice corrosion in stainless steel and nickel alloy reactor vessel internal components will be addressed by using the BWR vessel internals AMP to manage this aging effect.

In its letter dated March 30, 2006 (ML060950408), the applicant committed to revising the OCGS LRA, Section 3.1, to address loss of material due to pitting and crevice corrosion in stainless steel and nickel alloy reactor vessel internal components. The BWR vessel internals AMP will be used to manage this aging effect. **This is Audit Commitment 3.1.2.1.12-1.**

The project team reviewed the applicant's commitment and noted that the GALL Report recommends both the inservice inspection and water chemistry AMPs to manage loss of material for these RVI components. The project team reviewed the OCGS BWR vessel internals AMP and determined that this is part of the OCGS ISI AMP. In addition, although the applicant did not specifically identify the water chemistry AMP as one of the AMPs to manage this aging effect, the project team recognized that these RVI components are exposed to reactor water, and the quality of this water is treated in accordance with BWRVIP-130. Thus, the water chemistry AMP is also applicable to these RVI component. On this basis, the project team found the applicant's commitment to use the BWR vessel internals aging management program (AMP B.1.9) to manage this aging effect acceptable.

3.1.2.1.12 Reduction of Heat Transfer Due to Fouling

In OCGS LRA Table 3.1.2.1.1 for the isolation condenser system, the applicant proposed to manage reduction of heat transfer due to fouling for the internal and external surfaces of the stainless steel isolation condenser heat exchanger tubes exposed to treated water using the Water Chemistry Program (AMP B.1.2). However, the project team noted that the GALL Report recommends both the Water Chemistry Program (XI.M2) and the One-Time Inspection Program (XI.M32) to manage this aging effect. The applicant was asked to justify using the Water Chemistry Program alone to manage this aging effect.

In Attachment 3, Item EP-34 of its reconciliation document, the applicant stated that this line item for stainless steel heat exchanger tubes in treated water, addressing reduction of heat transfer due to fouling, invoked the Water Chemistry Program with no further evaluation required in January 2005 and has been changed in September 2005 to water chemistry and one-time inspection, with a further evaluation of aging effects. There are 2 instances of this line item being used in the Oyster Creek license renewal application, both in the isolation condenser system, for heat exchanger tubes, internal and external. Two new line items invoking the

One-Time Inspection Program for reduction of heat transfer due to fouling will be added to the OCGS LRA as a result of the change to the GALL Report.

The project team noted that the above revision to the LRA is included in audit commitment 3.2.2.2.4-1, which is discussed in Section 3.2.2.2.4.2 of this audit and review report.

Conclusion

The project team has evaluated the applicant's claim of consistency with the GALL Report and the above commitments. The project team also has reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the project team found that the AMR results, which the applicant claimed to be consistent with the GALL Report, are consistent with the AMRs in the GALL Report.

3.1.2.2 *AMR Results For Which Further Evaluation Is Recommended By The GALL Report*

Summary of Information in the Application

In OCGS LRA Section 3.1.2.2, the applicant provided further evaluation of aging management as recommended by the GALL Report for the isolation condenser system; nuclear boiler instrumentation system; reactor head cooling system; reactor internals; reactor pressure vessel; and reactor recirculation system components and component groups. The applicant also provided information concerning how it will manage the related aging effects.

Project Team Evaluation

For some AMR line-items assigned to the project team in the OCGS LRA Table 3.1.1, the GALL Report recommends further evaluation. When further evaluation is recommended, the project team reviewed these further evaluations provided in OCGS LRA Section 3.1.2.2 against the criteria provided in the SRP-LR Section 3.1.2.2. The project team's assessments of these evaluations is documented in this section. These assessments are applicable to each Table 2 AMR line-item in Section 3.1 citing the item in Table 1.

3.1.2.2.1 Cumulative Fatigue Damage

In OCGS LRA Section 3.1.2.2.1, the applicant stated that fatigue is a TLAA, as defined in 10 CFR 54.3. Applicants must evaluate TLAAs in accordance with 10 CFR 54.21(C)(1). During the audit, the project team determined that some of the TLAAs for the reactor vessel and its internals may not have explicit fatigue analysis calculations (therefore, they may not have the calculated cumulative usage factors), since the plant was originally designed based on ASME Power Piping Code B31.1. Specifically, in LRA Table 3.1.2.1.4 for the reactor internals, and Table 3.1.2.1.5 for the reactor pressure vessel, the applicant credited TLAA to manage cumulative fatigue damage for certain components. The applicant was asked to confirm that the cumulative usage factors for these components are available, and that fatigue cycles are tracked in order to manage the cumulative fatigue damage by TLAA in accordance with 10 CFR 54.21(c)(1)(I) or (ii), as claimed in the LRA.

In its response, the applicant stated that the use of TLAA as an aging management program in LRA Table 3.1.2.1.4 and Table 3.1.2.1.5 indicates that the current licensing basis was reviewed for TLAAs and the fatigue analysis was evaluated where one existed for that component. However, several components for which TLAA was identified as the aging management program for the cumulative fatigue aging effect do not have fatigue analyses. These components include the reactor internals (Table 3.1-1, item 5) and the control rod drive return line (CRDRL) nozzle and feedwater nozzle thermal sleeves (Table 3.1-1, item 2). In the absence of a fatigue analysis for these components, the effects of cumulative fatigue are managed by other AMPs, in accordance with 10 CFR 54.21(c)(1)(iii).

In its letter dated April 17, 2006 (ML 061150320), the applicant committed to revise the AMR line items in LRA Table 3.1.2.1.4 for the reactor internals, and Table 3.1.2.1.5 for the reactor pressure vessel to delete the reference to TLAA for components where a TLAA does not exist. Further, the appropriate aging management program will be identified with an "E" industry standard note and a plant specific note stating: "There is no fatigue analysis for this component. The aging effect of cumulative fatigue is managed by the BWR Vessel Internals aging management program." Similarly for the feedwater nozzle and CRD return line nozzle thermal sleeves, the note will read: "There is no fatigue analysis for this component. The aging effect of cumulative fatigue is managed by the BWR Feedwater Nozzle (or BWR CRD Return Line Nozzle, as applicable) aging management program." **This is Audit Commitment 3.1.2.2.1-1.**

The project team reviewed the applicant's response and found that, in the absence of a fatigue analysis for components for which a TLAA was credited, the effects of cumulative fatigue will be managed by other AMPs in accordance with 10 CFR 54.21(c)(1)(iii) and is acceptable.

The evaluation of the TLAAs was performed by NRR/DE staff and is addressed separately in Section 4 of the SER related to the OCGS LRA.

3.1.2.2.2 Loss of Material Due to General, Pitting, and Crevice Corrosion

3.1.2.2.2.1 Loss of Material Due to General, Pitting, and Crevice Corrosion [Item 1]

The project team reviewed OCGS LRA Section 3.1.2.2.2.1 against the criteria in SRP-LR Section 3.1.2.2.2.1.

SRP-LR Section 3.1.2.2.2.1 stated that loss of material due to general, pitting, and crevice corrosion could occur in the steel PWR steam generator shell assembly exposed to secondary feedwater and steam. Loss of material due to general, pitting, and crevice corrosion could also occur for the steel top head enclosure (without cladding) top head nozzles [vent, top head spray or reactor core isolation cooling (RCIC), and spare] exposed to reactor coolant. The existing program relies on control of reactor water chemistry to mitigate corrosion. However, control of water chemistry does not preclude loss of material due to pitting and crevice corrosion at locations of stagnant flow conditions. Therefore, the effectiveness of the chemistry control program should be verified to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to verify the effectiveness of the chemistry control program. A one-time inspection of select components at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or an aging effect is progressing very slowly such that the component's intended function will be maintained during the period of extended operation.

In Section 3.1.2.2.2.1 of the OCGS LRA, the applicant stated that loss of material due to general, pitting, and crevice corrosion in a PWR steel steam generator shell assembly is applicable to PWRs only. The project team concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek is a BWR plant.

With regard to loss of material due to general, pitting, and crevice corrosion for the steel top head enclosure (without cladding) top head nozzles, the applicant stated that the Oyster Creek top head enclosure is clad with stainless steel and not subject to loss of material from general, pitting and crevice corrosion and therefore, no aging program is required. The project team concurred with the applicant's evaluation since the stainless steel cladding precludes general, pitting, and crevice corrosion.

3.1.2.2.2.2 Loss of Material Due to General, Pitting, and Crevice Corrosion [Item 2]

The project team reviewed OCGS LRA Section 3.1.2.2.2.2 against the criteria in SRP-LR Section 3.1.2.2.2.2.

SRP-LR Section 3.1.2.2.2.2 stated that loss of material due to pitting and crevice corrosion could occur in stainless steel BWR isolation condenser components exposed to reactor coolant. Loss of material due to general, pitting, and crevice corrosion could occur in steel BWR isolation condenser components. The existing program relies on control of reactor water chemistry to mitigate corrosion. However, control of water chemistry does not preclude loss of material due to pitting and crevice corrosion at locations of stagnant flow conditions. Therefore, the effectiveness of the chemistry control program should be verified to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to verify the effectiveness of the chemistry control program. A one-time inspection of select components at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or an aging effect is progressing very slowly such that the component's intended function will be maintained during the period of extended operation.

In the OCGS LRA, Section 3.1.2.2.2.2, the applicant stated that Oyster Creek will use the Water Chemistry Program, B.1.2, to manage aging of stainless steel tube side components of the isolation condenser system exposed to reactor coolant. The program activities provide for monitoring and controlling of water chemistry using station procedures and processes for the prevention or mitigation of loss of material aging effects. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program, B.1.1, will be used with the Water Chemistry Program to manage loss of material. The ASME Section XI Inservice Inspection program will be enhanced to perform inspection of the isolation condenser tube side components, including temperature and radioactivity monitoring of the shell-side water, eddy current testing of the tubes, and inspection (VT or UT) of the tubesheet and channel head to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period of operation. Observed conditions that have the potential for impacting the intended function are evaluated or corrected in accordance with the corrective action process.

During a teleconference on February 2, 2006, the applicant indicated that, thus far no augmented inspections have been performed on components associated with the isolation condenser, and that the proposed augmented inspections will be applicable as a part of an aging management program (AMP) during the extended period of operation. In RAI-3.1.1-1, dated March 20, 2006 (ML060550419), the staff requested that the applicant provide the following information so that an assessment can be made as to the effectiveness of the future augmented inspection program of the isolation condenser and its components.

(1) Previous experience related to the frequency of occurrence of pitting and crevice corrosion in the isolation condenser and its components.

(2) Previous inspection methods and the inspection frequency that were implemented prior to the replacement of some of the isolation condenser components.

(3) Criteria for establishing future augmented inspection frequency.

In its letter dated April 18, 2006 (ML061100138), the applicant provided the following response to the RAI.

The carbon steel Isolation Condenser shells were fabricated with a nominal thickness of 0.375 inches, with a corrosion allowance of 0.100 inches. In 1996, NDE tests were performed on the Isolation Condenser "B" shell to determine the existence and extent of pitting corrosion. Plant experience has indicated that the condition of the "B" isolation condenser is the more limiting of the two condensers. The results of the NDE tests showed an average shell thickness of 0.389 inches with a standard deviation of 0.014 inches. In 2002, the "B" isolation condenser shell was again examined. Visual examination results indicated blistering of the coating at or near the waterline. NDE results from tests performed at locations just below the waterline judged to have the highest probability for accelerated corrosion yielded readings well within the control limits computed from the 1996 readings, and above or close to the fabrication nominal thickness of 0.375 inches.

Prior to tube bundle replacement in the Oyster Creek isolation condensers, the stainless steel tube bundles were found to be subject to crevice corrosion. Tube OD crevice corrosion located in the crevice formed by the roll expansion process during tube bundle fabrication was accelerated by elevated isolation condenser temperatures due in part to condensate return valve leakage. In addition, numerous thermal cycles were caused by isolation condenser water level oscillation due to the valve leakage condition, and system service as the primary heat sink during reactor shutdowns employing opening and closing of the condensate return valves as needed to limit cooldown rate. Subsequent correction of the condensate return valve leakage condition and changes to isolation condenser operation strategy during reactor cooldown have significantly reduced the thermal cycling that exacerbated the crevice corrosion conditions which existed in the original tube bundle assemblies.

In 1996 and again in 2002, VT and UT inspection methods were used to evaluate the condition of the isolation condenser shell. During the evaluation of the isolation condenser tube leakage conditions, UT and thermography testing were used to determine the condensate/steam interface in the isolation condensers, and acoustic monitoring of boiling intensity was used to determine the presence of stratified tube internal conditions. Weekly temperature monitoring of isolation condenser temperature and monthly radioactivity sampling of the shell water (subsequently changed to weekly) have been performed since before tube bundle replacement.

Correction of the valve leakage condition has significantly reduced the number of isolation condenser water level oscillations and resultant thermal cycles applied to the isolation condenser components. The Oyster Creek isolation condenser tube bundles were replaced in the "A" isolation condenser in 2000 and in the "B" isolation condenser in 1998, utilizing improved materials that are more resistant to intergranular stress corrosion

> cracking. The physical configuration of the isolation condensers and internal surfaces of the channel head require cutting and re-welding of pressure boundary piping. Because of the significant reduction in frequency of initiating conditions, and the relatively recent replacement of the tube bundles with improved materials, these inspections will be performed once during the first ten years of the period of extended operation. Radioactivity and temperature monitoring of the shell side water, as specified in the GALL recommendations for isolation condenser aging management, are currently being performed weekly, and will continue throughout the period of extended operation. Additionally, during the NRC Region 1 Inspection, AmerGen has committed to performing a one-time UT inspection of the "B" Isolation Condenser shell for pitting corrosion, prior to the period of extended operation. Plant experience has indicated that the condition of the "B" isolation condenser is the more limiting of the two condensers. This commitment will be added to the Table A.5 License Renewal Commitment List Item No. 24. **This is Audit Commitment 3.1.2.2.2-1**.

In a follow-up discussion, the staff asked the applicant to clarify its planned corrective action activities if there any tube leakage observed. In its letter (2130-06-20331) dated May 3, 2006, the applicant stated that:

> Should any of the monitoring activities conducted on the isolation condensers reveal conditions potentially indicative of a tube leak, initiation of the corrective action process would result in an engineering evaluation of the observed condition. Confirmatory testing could be performed, which may include controlled-inventory testing of the shell water volume with the bundle side pressurized, and enhanced radioactivity analysis of shell side water. Upon confirmation of tube leakage, repair or plugging of leaking tubes would be performed, and if warranted, eddy current testing of the bundles to determine extent of condition would be considered. Conceivably, depending on the extent, repair could consist of tube bundle replacement. Appropriate corrective action to correct a tube leakage condition in the isolation condensers would be taken, regardless of when it occurred during the period of extended operation.

The project team reviewed the applicant’s response to the RAI, Water Chemistry Program (AMP B.1.2) and ASME Section XI ISI, Subsection IWB, IWC and IWD program (AMP B.1.1) and determined that these programs and the commitment to perform one-time UT inspection of ?B” Isolation Condenser include activities that are adequate to manage loss of material due to pitting and crevice corrosion in stainless steel BWR isolation condenser components. The project team determined that the loss of material in the isolation condenser components exposed to reactor coolant will be adequately managed by the inservice inspection and water chemistry programs.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.1.2.2.2.2 for further evaluation.

3.1.2.2.2.3 Loss of Material Due to General, Pitting, and Crevice Corrosion [Item 3]

The applicant addressed loss of material due to pitting and crevice corrosion for stainless steel, nickel alloy, and steel with nickel alloy or stainless steel cladding reactor vessel flanges, nozzles, penetrations, safe ends, vessel shells, heads and welds exposed to reactor coolant in Attachment 7, Item RP-25 of its reconciliation document. The applicant also addressed loss of material due to pitting and crevice corrosion for stainless steel, steel with nickel alloy or stainless steel cladding, and nickel alloy reactor coolant pressure boundary components exposed to reactor coolant in Attachment 7, Item RP-27 of its reconciliation document. Therefore, the project team reviewed those evaluations against the criteria in SRP-LR Section 3.1.2.2.3. RP-25 and RP-27 were new AMR line items that were not in the draft January 2005 GALL Report.

SRP-LR Section 3.1.2.2.3 stated that loss of material due to pitting and crevice corrosion could occur for stainless steel, nickel alloy, and steel with stainless steel or nickel alloy cladding flanges, nozzles, penetrations, pressure housings, safe ends, and vessel shells, heads and welds exposed to reactor coolant. The existing program relies on control of reactor water chemistry to mitigate corrosion. However, control of water chemistry does not preclude loss of material due to pitting and crevice corrosion at locations of stagnant flow conditions. Therefore, the effectiveness of the chemistry control program should be verified to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to verify the effectiveness of the chemistry control program. A one-time inspection of select components at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or an aging effect is progressing very slowly such that the component's intended function will be maintained during the period of extended operation.

In Attachment 7, Item RP-25 of its reconciliation document, the applicant stated that the specifications of new line item RP-25 will be addressed as follows: The aging effect of loss of material due to pitting and crevice corrosion in reactor vessel flanges, nozzles, penetrations, pressure housings, safe ends, and vessel shells, heads and welds will be managed through the use of the water chemistry and one-time inspection programs. The selection of susceptible locations for one-time inspections will be based on severity of conditions, time of service, and lowest design margin.

In its letter dated March 30, 2006 (ML060950408), the applicant committed to revise the OCGS LRA Section 3.1 to address loss of material due to pitting and crevice corrosion for stainless steel, nickel alloy, and steel with stainless steel or nickel alloy cladding flanges, nozzles, penetrations, pressure housings, safe ends, and vessel shells, heads and welds exposed to reactor coolant. The aging effect will be managed through the use of the water chemistry and one-time inspection programs. The selection of susceptible locations for one-time inspections will be based on severity of conditions, time of service, and lowest design margin. **This is Audit Commitment 3.1.2.2.2-2.**

The project team reviewed the applicant's Water Chemistry Program (AMP B.1.2) and verified that this aging management program include activities that will manage loss of material due to pitting and crevice corrosion. In addition, the project team reviewed the applicant's One-Time Inspection Program (B.1.24) and verified that this aging management program includes inspections of the reactor vessel internals to detect loss of material as a means of verifying the effectiveness of the Water Chemistry Program. The project team determined that these AMPs will adequately manage loss of material due to pitting and crevice corrosion in reactor vessel flanges, nozzles, penetrations, pressure housings, safe ends, and vessel shells, heads and welds.

In Attachment 7, Item RP-27 of its reconciliation document, the applicant stated that for piping, piping components, and piping elements in reactor coolant pressure boundary systems and systems with RCPB interface, the Oyster Creek LRA used line items EP-32, A-58, and AP-57 for loss of material due to pitting and crevice corrosion of stainless steel in treated water (including reactor coolant), using the water chemistry and one-time inspection programs. This is in conformance with the September 2005 Revision 1 of GALL.

The project team reviewed line items EP-32, A-58, and AP-57 in the GALL Report and determined that these line items address loss of material due to pitting and crevice corrosion of stainless steel in treated water, and recommend using the water chemistry and one-time inspection programs to manage this aging. Therefore, the project team found the applicant's evaluation acceptable since it is consistent with GALL.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.1.2.2.2.3 for further evaluation.

3.1.2.2.2.4 Loss of Material Due to General, Pitting, and Crevice Corrosion [Item 4]

Loss of material due to general, pitting, and crevice corrosion in the steel PWR steam generator upper and lower shell and transition cone exposed to secondary feedwater and steam is applicable to PWRs only. The project team determined that this aging effect is not applicable since Oyster Creek is a BWR plant.

3.1.2.2.3 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement

3.1.2.2.3.1 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement [Item 1]

The project team reviewed OCGS LRA Section 3.1.2.2.3.1 against the criteria in SRP-LR Section 3.1.2.2.3.1.

SRP-LR Section3.1.2.2.3.1 stated that neutron irradiation embrittlement is a TLAA to be evaluated for the period of extended operation for all ferritic materials that have a neutron fluence greater than 10^{17} n/cm2 (E >1 MeV) at the end of the license renewal term. Certain aspects of neutron irradiation embrittlement are TLAAs as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in Section 4.2, ?Reactor Vessel Neutron Embrittlement Analysis," of this SRP-LR.

In the OCGS LRA Section 3.1.2.2.3.1, the applicant stated that for Oyster Creek, the effects of increased neutron fluence on the fracture toughness of the reactor vessel beltline plates and welds is discussed in Section 4.2 of the OCGS LRA. Also discussed in Section 4.2 is the impact on the vessel's temperature – pressure curves and weld exam requirements.

TLAAs were evaluated by the NRR/DE staff and will be documented in the SER related to the OCGS LRA.

3.1.2.2.3.2 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement [Item 2]

The project team reviewed OCGS LRA Section 3.1.2.2.3.2 against the criteria in SRP-LR Section 3.1.2.2.3.2.

SRP-LR Section 3.1.2.2.3.2 stated that loss of fracture toughness due to neutron irradiation embrittlement could occur in BWR and PWR reactor vessel beltline shell, nozzle, and welds exposed to reactor coolant and neutron flux. A reactor vessel materials surveillance program monitors neutron irradiation embrittlement of the reactor vessel. Reactor vessel surveillance program is plant-specific, depending on matters such as the composition of limiting materials, availability of surveillance capsules, and projected fluence levels. In accordance with 10 CFR Part 50, Appendix H, an applicant is required to submit its proposed withdrawal schedule for approval prior to implementation. Untested capsules placed in storage must be maintained for future insertion. Thus, further staff evaluation is required for license renewal. Specific recommendations for an acceptable AMP are provided in Chapter XI, Section M31 of the GALL Report.

In the OCGS LRA Section 3.1.2.2.3.2, the applicant stated that the Oyster Creek reactor vessel surveillance program, B.1.23, is based on the BWR integrated surveillance program (ISP) and satisfies the requirements of 10 CFR Part 50, Appendix H. The reactor vessel surveillance aging management program includes periodic testing of metallurgical surveillance samples to monitor the progress of neutron embrittlement of the reactor pressure vessel as a function of neutron fluence, in accordance with Regulatory Guide (RG) 1.99, ?Radiation Embrittlement of Reactor Vessel Materials," Revision 2. BWRVIP-116 identifies and schedules additional capsules to be withdrawn and tested during the license renewal period. Oyster Creek will continue to participate in using the integrated surveillance program during the period of extended operation by implementing the recommendations of BWRVIP-116, and by addressing any additional actions required by the associated NRC Safety Evaluation with BWRVIP-116, once it is approved. Observed conditions that have the potential for impacting the intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's further evaluation and determined that the reactor vessel surveillance program (AMP B.1.23) is appropriate to manage the loss of fracture toughness due to neutron irradiation embrittlement in reactor vessel beltline shell, nozzle, and welds exposed to reactor coolant and neutron flux The technical evaluation of this program to determine its adequacy was performed by NRR/DE staff, and is addressed in the SER related to the OCGS LRA.

3.1.2.2.4 Cracking Due to Stress Corrosion Cracking and Intergranular Stress Corrosion Cracking

3.1.2.2.4.1 Cracking Due to Stress Corrosion Cracking and Intergranular Stress Corrosion Cracking [Item 1]

The applicant addressed cracking due to SCC and IGSCC in the top head enclosure vessel flange leak detection lines in LRA Section 3.1.2.2.4.2, in accordance with the draft January 2005 SRP-LR. Therefore the project team reviewed OCGS LRA Section 3.1.2.2.4.2 against the criteria in SRP-LR Section 3.1.2.2.4.1.

SRP-LR Section 3.1.2.2.4.1 stated that cracking due to SCC and IGSCC could occur in the stainless steel and nickel alloy BWR top head enclosure vessel flange leak detection lines. The GALL Report recommends that a plant-specific AMP be evaluated because existing programs may not be capable of mitigating or detecting cracking due to SCC and IGSCC.

In the OCGS LRA Section 3.1.2.2.4.2, the applicant stated that Oyster Creek will use the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program, B.1.1, to ensure the reactor vessel flange leak detection lines are not experiencing aging effects caused by SCC and IGSCC. The Oyster Creek ISI program utilizes a VT-2 visual examination on the line prior to reactor cavity drain down during each refueling outage. This examination will be credited for managing cracking. Observed conditions that have the potential for impacting the intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program, B.1.1, and determined that it will adequately manage the effects of stress corrosion cracking in the stainless steel vessel flange leak detection line. Moreover, a VT-2 visual examination of the line prior to reactor cavity drain down during each refueling outage will provide an additional method for detecting any incipient degradation.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.1.2.2.4.1 for further evaluation.

3.1.2.2.4.2 Cracking Due to Stress Corrosion Cracking and Intergranular Stress Corrosion Cracking [Item 2]

The applicant addressed cracking due to SCC and IGSCC in the stainless steel isolation condenser components in LRA Section 3.1.2.2.4.3, in accordance with the draft January 2005 SRP-LR. Therefore the project team reviewed OCGS LRA Section 3.1.2.2.4.3 against the criteria in SRP-LR Section 3.1.2.2.4.2.

SRP-LR Section 3.1.2.2.4.2 stated that cracking due to SCC and IGSCC could occur in stainless steel BWR isolation condenser components exposed to reactor coolant. The existing program relies on control of reactor water chemistry to mitigate SCC, and on ASME Section XI ISI. However, the existing program should be augmented to detect cracking due to SCC and IGSCC. The GALL Report recommends an augmented program to include temperature and radioactivity monitoring of the shell-side water, and eddy current testing of tubes to ensure that the component's intended function will be maintained during the period of extended operation.

In the OCGS LRA Section 3.1.2.2.4.3, the applicant stated that Oyster Creek will use the Water Chemistry Program, B.1.2, to manage aging of stainless steel tube side components of the isolation condenser system exposed to reactor coolant. The program activities provide for monitoring and controlling of water chemistry using station procedures and processes for the prevention or mitigation of cracking due to stress corrosion cracking and IGSCC. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program, B.1.1, will be used with the Water Chemistry Program to manage the aging effects of stress corrosion cracking and IGSCC. The ASME Section XI Inservice Inspection program will be enhanced to perform inspection of the isolation condenser tube side components, including temperature and radioactivity monitoring of the shell-side water, eddy current testing of the tubes, and inspection (VT or UT) of the tubesheet and channel head to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period of operation. Observed conditions that have the potential for impacting the intended function are evaluated or corrected in accordance with the corrective action process.

During the teleconference dated February 2, 2006, the applicant indicated that thus far no augmented inspections were performed on components associated with an isolation condenser and that the proposed augmented inspections will be applicable as a part of an AMP during the extended period of operation. The staff requested that the applicant provide the following information so that an assessment can be made as to the effectiveness of the future augmented inspection program of the isolation condenser and its components.

(1) Previous experience related to the frequency of occurrence of SCC and IGSCC in the isolation condenser and its components.

(2) Previous inspection methods and the inspection frequency that were implemented prior to the replacement of some of the isolation condenser components.

(3) Criteria for establishing future augmented inspection frequency.

In its letter dated April 18, 2006 (ML061100138), the applicant provided the following response to the RAI.

> Prior to tube bundle replacement in the Oyster Creek isolation condensers, the stainless steel tube bundles were found to be subject to stress corrosion cracking. Fatigue propagated cracks on the OD surface of the tubes initiated by trans-granular stress corrosion cracking, and fatigue cracks at the seal weld and portions of the tubesheet adjacent to the seal weld were caused by oscillating conditions internal to the tubes due to condensate return valve leakage. Numerous thermal cycles were caused by isolation condenser water level oscillation due to the valve leakage condition, and system service as the primary heat sink during reactor shutdowns employing opening and closing of the condensate return valves as needed to limit cooldown rate. Subsequent correction of the condensate return valve leakage condition and changes to isolation condenser operation strategy during reactor cooldown have significantly reduced the thermal cycling that exacerbated the stress corrosion cracking conditions which existed in the original tube bundle assemblies.
>
> During the evaluation of the isolation condenser tube leakage conditions, UT and thermography testing were used to determine the condensate/steam interface in the isolation condensers, and acoustic monitoring of boiling intensity was used to determine the presence of stratified tube internal conditions. Weekly temperature monitoring of isolation condenser temperature and monthly radioactivity sampling of the shell water (subsequently changed to weekly) has been performed since before tube bundle replacement.
>
> Correction of the valve leakage condition has significantly reduced the number of isolation condenser water level oscillations and resultant thermal cycles applied to the isolation condenser components. The Oyster Creek isolation condenser tube bundles were replaced in the "A" isolation condenser in 2000 and in the "B" isolation condenser in 1998, utilizing improved materials that are more resistant to intergranular stress corrosion cracking. Due to the physical configuration of the isolation condensers and piping at Oyster Creek, eddy current inspection of the tubes and access to the tubesheet and internal surfaces of the channel head require cutting and re-welding of pressure boundary piping. Because of the significant reduction in frequency of initiating conditions, and the relatively recent replacement of the tube bundles with improved materials, these inspections will be performed once during the first ten years of the period of extended operation. Radioactivity and temperature monitoring of the shell side water as specified in the GALL recommendations for isolation condenser aging management are currently being performed weekly and will continue throughout the period of extended operation. Additionally, during the NRC Region I Inspection, AmerGen has committed to performing a one-time UT inspection of the "B" Isolation Condenser shell for pitting corrosion, prior to the period of extended operation. Plant experience has indicated that the condition of the "B" isolation condenser is the more limiting of the two condensers. This commitment will be added to the Table A.5 License Renewal Commitment List Item No. 24. See commitment identified in 3.1.2.2.2.2-1.

In a follow-up discussion, the staff asked the applicant to clarify its planned corrective action activities if there any tube leakage observed. In its letter (2130-06-20331) dated May 3, 2006, the applicant stated that:

> Should any of the monitoring activities conducted on the isolation condensers reveal conditions potentially indicative of a tube leak, initiation of the corrective action process would result in an engineering evaluation of the observed condition. Confirmatory testing could be performed, which may include controlled-inventory testing of the shell water volume with the bundle side pressurized, and enhanced radioactivity analysis of shell side water. Upon confirmation of tube leakage, repair or plugging of leaking tubes would be performed, and if warranted, eddy current testing of the bundles to determine extent of condition would be considered. Conceivably, depending on the extent, repair could consist of tube bundle replacement. Appropriate corrective action to correct a tube leakage condition in the isolation condensers would be taken, regardless of when it occurred during the period of extended operation.

The project team reviewed the applicant's response to the RAI, Water Chemistry Program (AMP B.1.2) and ASME Section XI ISI, Subsection IWB, IWC and IWD program (AMP B.1.1) and determined that these programs and the commitment to perform one-time UT inspection of ?B" Isolation Condenser include activities that are adequate to manage cracking due to SCC and IGSCC in stainless steel BWR isolation condenser components exposed to reactor coolant. The project team determined that the aging effects due to SCC, IGSCC associated with isolation condenser systems components will be adequately managed by the inservice inspection and water chemistry programs.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.1.2.2.4.2 for further evaluation.

3.1.2.2.5 Crack Growth Due to Cyclic Loading

In Section 3.1.2.2.5 of the OCGS LRA, the applicant stated that cracking due to cyclic loading of PWR vessel shells is applicable to PWRs only. The project team concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek is a BWR plant.

3.1.2.2.6 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement and Void Swelling

In Section 3.1.2.2.6 of the OCGS LRA, the applicant stated that loss of fracture toughness of PWR reactor internals is applicable to PWRs only. The project team concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek is a BWR plant.

3.1.2.2.7 Cracking Due to Stress Corrosion Cracking

3.1.2.2.7.1 Cracking Due to Stress Corrosion Cracking [Item 1]

In Section 3.1.2.2.7.1 of the OCGS LRA, the applicant stated that cracking due to stress corrosion cracking for PWR components made out of stainless steel is applicable to PWRs only. The project team concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek is a BWR plant.

3.1.2.2.7.2 Cracking Due to Stress Corrosion Cracking [Item 2]

In Section 3.1.2.2.7.2 of the OCGS LRA, the applicant stated that cracking due to stress corrosion cracking of PWR Class 1 CASS piping, piping components, and piping elements is applicable to PWRs only. The project team concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek is a BWR plant.

3.1.2.2.8 Cracking Due to Cyclic Loading

3.1.2.2.8.1 Cracking Due to Cyclic Loading [Item 1]

The project team reviewed OCGS LRA Section 3.1.2.2.8.1 against the criteria in SRP-LR Section 3.1.2.2.8.1.

SRP-LR Section 3.1.2.2.8.1stated that cracking due to cyclic loading could occur in the stainless steel BWR jet pump sensing lines. The GALL Report recommends that a plant specific AMP be evaluated to ensure that this aging effect is adequately managed.

In the OCGS LRA Section 3.1.2.2.8.1, the applicant stated that this item is not applicable to Oyster Creek. Oyster Creek does not have jet pumps or jet pump sensing lines.

The project team determined that the OCGS reactor does not have jet pumps and therefore, concurred with the applicant's evaluation that this aging effect/mechanism is not applicable.

3.1.2.2.8.2 Cracking Due to Cyclic Loading [Item 2]

The applicant addressed cracking due to cyclic loading in the isolation condenser components in LRA Section 3.1.2.2.4.3, in accordance with the draft January 2005 SRP-LR. Therefore, the project team reviewed OCGS LRA Section 3.1.2.2.4.3 against the criteria in SRP-LR Section 3.1.2.2.8.2.

SRP-LR Section 3.1.2.2.8.2 stated that cracking due to cyclic loading could occur in steel and stainless steel BWR isolation condenser components exposed to reactor coolant. The existing program relies on ASME Section XI ISI. However, the existing program should be augmented to detect cracking due to cyclic loading. The GALL Report recommends an augmented program to include temperature and radioactivity monitoring of the shell-side water, and eddy current testing of tubes to ensure that the component's intended function will be maintained during the period of extended operation.

The project team reviewed the applicant's Water Chemistry Program (AMP B.1.2) and ASME Section XI ISI program (AMP B.1.1), and determined that they are adequate to manage cracking due to cyclic loading in the isolation condenser components exposed to reactor coolant. In addition, the project team found that the augmented inspections proposed by the applicant for the OCGS ASME Section XI ISI, Subsections IWB, IWC, and IWD program are consistent with the GALL Report recommendations.

The project team found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.1.2.2.8.2 for further evaluation.

3.1.2.2.9 Loss of Preload Due to Stress Relaxation

In Section 3.1.2.2.9 of the OCGS LRA, the applicant stated that loss of preload due to stress relaxation of PWR RVI components is applicable to PWRs only. The project team concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek is a BWR plant.

3.1.2.2.10 Loss of Material Due to Erosion

In Section 3.1.2.2.10 of the OCGS LRA, the applicant stated that loss of material due to erosion of PWR steam generator components is applicable to PWRs only. The project team concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek is a BWR plant.

3.1.2.2.11 Cracking Due to Flow-Induced Vibration

The project team reviewed OCGS LRA Section 3.1.2.2.11 against the criteria in SRP-LR Section 3.1.2.2.11.

SRP-LR Section 3.1.2.2.11 stated that cracking due to flow-induced vibration could occur for the BWR stainless steel steam dryers exposed to reactor coolant. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that this aging effect is adequately managed.

In the OCGS LRA Section 3.1.2.2.11, the applicant stated that Oyster Creek will use the reactor internals program, B.1.9, to manage to the effects of cracking of the steam dryer. The applicant also stated that it will implement the guidelines of BWRVIP-139 for the steam dryer when issued. Observed conditions that have the potential for impacting the intended function are evaluated or corrected in accordance with the corrective action process.

The applicant was asked to describe how cracking in the steam dryer will be managed by the BWR vessel internals and water chemistry AMPs during the period of extended operation. In its response, the applicant stated that Oyster Creek has been inspecting the steam dryer every refueling outage for many years. In 1984 (10R) a cracked brace weld was found in bank 4-5, which was underwater weld repaired in the equipment storage pool. In 1986 a cracked brace weld was found in bank 5-6, which was underwater weld repaired in the equipment storage pool. No indications of cracking were found in the 1989 and 1991 refueling outages. In 1992 the previously repaired brace weld (bank 5-6) was found cracked and a second weld repair was implemented by underwater welding in the equipment storage pool. Stiffeners were added to the vertical plates where cracked. In 1994 the same bank 5-6 brace weld was found cracked. A different repair method, ?stop drilling", was implemented to eliminate cracking propagation. Visual inspections of the Steam Dryer performed in 1996, 1998, 2000, 2002, and 2004 found no signs of cracking, which indicates the stop drilling repair has been effective.

The applicant further stated that currently, the steam dryer is inspected in accordance with the recommendation of SIL 644, Revision 1. Inspections in 2006 will continue to follow the inspections of SIL 644. The Oyster Creek inspection is not impacted by the comments on SIL 644 provided the NRC staff to the BWR Owners Group (BWROG) in Jan 2005 [Letter Report from Robert A Gramm of NRC to Kenneth S Putnam of BWROG, dated January 12, 2005]. The NRC comments primarily address concerns associated with extended power uprate (EPU). Oyster Creek has not implemented EPU, nor is such an uprate planned.

For the period of extended operation, the applicant stated that the BWRVIP-139 dryer inspections already performed are meant to establish a baseline. The results of these inspections will be evaluated to establish future scope and schedule for steam dryer inspections. Oyster Creek will comply with the recommendations of the BWRVIP regarding steam dryer inspections. Any flaws found during inspections will be evaluated and reinspection performed, if required. Performing the inspections in accordance with BWRVIP-139 provides assurance that the steam dryer will perform its intended function during the period of extended operation.

The project team reviewed the applicant's response and determined that it represents an adequate method of managing cracking in the steam dryers during the period of extended operation. The use of baseline inspections to compare future inspection results will provide a means of determining if any new cracking is occurring, which would require further action. The project team determined that the applicant's approach is acceptable.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.1.2.2.11 for further evaluation.

3.1.2.2.12 Cracking Due to Stress Corrosion Cracking and Irradiation-Assisted Stress Corrosion Cracking (IASCC)

In Section 3.1.2.2.12 of the OCGS LRA, the applicant stated that cracking due to SCC and IASCC of PWR RVI components is applicable to PWRs only. The project team concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek is a BWR plant.

3.1.2.2.13 Cracking Due to Primary Water Stress Corrosion Cracking (PWSCC)

In Section 3.1.2.2.13 of the OCGS LRA, the applicant stated that cracking due to primary water SCC of PWR components inside the reactor vessel is applicable to PWRs only. The project team concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek is a BWR plant.

3.1.2.2.14 Wall Thinning Due to Flow-Accelerated Corrosion

In Section 3.1.2.2.14 of the OCGS LRA, the applicant stated that wall thinning due to flow-accelerated corrosion of PWR steam generator feedwater inlet ring and supports is applicable to PWRs only. The project team concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek is a BWR plant.

3.1.2.2.15 Changes in Dimensions Due to Void Swelling

In Section 3.1.2.2.15 of the OCGS LRA, the applicant stated that changes in dimensions due to void swelling of PWR RVI components is applicable to PWRs only. The project team concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek is a BWR plant.

3.1.2.2.16 Cracking Due to Stress Corrosion Cracking and Primary Water Stress Corrosion Cracking

3.1.2.2.16.1 Cracking Due to Stress Corrosion Cracking and Primary Water Stress Corrosion Cracking [Item 1]

In Section 3.1.2.2.16.1 of the OCGS LRA, the applicant stated that cracking due to SCC and primary water SCC of PWR CRD penetration components is applicable to PWRs only. The project team concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek is a BWR plant.

3.1.2.2.16.2 Cracking Due to Stress Corrosion Cracking and Primary Water Stress Corrosion Cracking [Item 2]

In Section 3.1.2.2.16.2 of the OCGS LRA, the applicant stated that cracking due to SCC and primary water SCC of PWR pressurizer head spray components is applicable to PWRs only. The project team concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek is a BWR plant.

3.1.2.2.17 Cracking Due to Stress Corrosion Cracking, Primary Water Stress Corrosion Cracking, and Irradiation-Assisted Stress Corrosion Cracking

In Section 3.1.2.2.17 of the OCGS LRA, the applicant stated that cracking due to SCC, primary water SCC, and IASCC of PWR RVI components is applicable to PWRs only. The project team concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek is a BWR plant.

3.1.2.2.18 Quality Assurance for Aging Management of Non-safety-Related Components

OCGS LRA Section 3.1.2.2.18 is reviewed by NRR/DE staff and will be addressed separately in Section 3 of the SER related to the OCGS LRA.

Conclusion

On the basis of its review, for component groups evaluated in the GALL Report for which the GALL Report recommends further evaluation, the project team determined that the applicant adequately addressed the issues that were further evaluated.

3.1.2.3 *AMR Results That Are Not Consistent With The GALL Report Or Not Addressed In The GALL Report*

Summary of Information in the Application

In OCGS LRA Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System, the applicant provided information regarding components or material/environment combination in the GALL Report that it evaluated and identified as not applicable to its plant.

In OCGS LRA Tables 3.1.2.1.1 through 3.1.2.1.6, the applicant provided additional details of the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that are not consistent with the GALL Report. Specifically, the applicant indicated, via Notes F through J, that neither the identified component nor the material/environment combination is evaluated in the GALL Report and provided information concerning how the aging effect requiring management will be managed.

Project Team Evaluation

The project team reviewed additional details of the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that the applicant identified as not applicable to its plant.

The project team did not review the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that are not consistent with the GALL Report or are not addressed in the GALL Report. These AMR line items were reviewed by NRR/DE staff, and are discussed in the SER related to the OCGS LRA.

3.1.2.3.1 Aging Effects/mechanisms in Table 3.1.1 That Are Not Applicable for OCGS

The project team reviewed OCGS LRA Table 3.1.1, which provides a summary of aging management evaluations for the reactor vessel, internals, and reactor coolant systems evaluated in the GALL Report.

In OCGS LRA Table 3.1.1, Items 3.1.1-39 and 3.1.1-41, the applicant stated that cracking due to stress corrosion cracking, intergranular stress corrosion cracking, or irradiation-assisted stress corrosion cracking of nickel alloy core shroud and core plate access hole cover (welded and mechanical covers) in the reactor vessel, internals, and reactor coolant system is not applicable at OCGS. Oyster Creek has no access holes or hole covers in the shroud support plate in the reactor vessel, internals, or reactor coolant system.

The project team reviewed the reactor vessel, internals, and reactor coolant system AMR line items in the OCGS LRA and determined that Oyster Creek has no access holes or hole covers in the shroud support plate. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.1.1, Item 3.1.1-40, the applicant stated that loss of material due to general, pitting and crevice corrosion of steel top head enclosure (without cladding) top head nozzles (vent, top head spray or RCIC, and spare) exposed to reactor coolant in the reactor vessel, internals, and reactor coolant system is not applicable at OCGS. The Oyster Creek top head enclosure is clad with stainless steel and not subject to loss of material from general, pitting and crevice corrosion. No aging program is required.

The project team reviewed the reactor vessel, internals, and reactor coolant system AMR line items in the OCGS LRA and determined that the top head enclosure is clad with stainless steel and not subject to loss of material from general, pitting and crevice corrosion. Therefore, the project team concurred with the applicant's conclusion that no aging program is required.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.1.1, Item 3.1.1-45, the applicant stated that loss of material due to pitting, crevice and galvanic corrosion of copper alloy piping, piping components, and piping elements exposed to closed-cycle cooling water in the reactor vessel, internals, and reactor coolant system is not applicable at OCGS. Oyster Creek has no copper alloy piping, piping components, or piping elements exposed to a closed cycle cooling water environment in the reactor vessel, internals, or reactor coolant system.

The project team reviewed the reactor vessel, internals, and reactor coolant system AMR line items in the OCGS LRA and determined that Oyster Creek has no copper alloy piping, piping components, and piping elements exposed to closed-cycle cooling water. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.1.1, Item 3.1.1-46, the applicant stated that loss of material due to general, pitting and crevice corrosion of steel piping, piping components, and piping elements exposed to closed-cycle cooling water in the reactor vessel, internals, and reactor coolant system is not applicable at OCGS. Oyster Creek has no stainless steel piping, piping components, or piping elements exposed to a closed cycle cooling water environment in the reactor vessel, internals, or reactor coolant system.

The project team reviewed the reactor vessel, internals, and reactor coolant system AMR line items in the OCGS LRA and determined that Oyster Creek has no steel piping, piping components, and piping elements exposed to closed-cycle cooling water. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.1.1, Item 3.1.1-48, the applicant stated that loss of material due to selective leaching of copper alloy >15% Zn piping, piping components, and piping elements exposed to closed-cycle cooling water in the reactor vessel, internals, and reactor coolant system is not applicable at OCGS. Oyster Creek has no copper alloy >15% Zn piping, piping components, and piping elements exposed to closed-cycle cooling water in the reactor vessel, internals, or reactor coolant system.

The project team reviewed the reactor vessel, internals, and reactor coolant system AMR line items in the OCGS LRA and determined that Oyster Creek has no copper alloy >15% Zn piping, piping components, and piping elements exposed to closed-cycle cooling water in the reactor vessel, internals, or reactor coolant system. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.1.1, Item 3.1.1-49, the applicant stated that loss of fracture toughness due to thermal aging embrittlement of cast austenitic stainless steel piping and CRD pressure housings in the reactor vessel, internals, and reactor coolant system is not applicable at OCGS. Oyster Creek has no cast austenitic stainless steel piping that is subject to loss of fracture toughness due to thermal aging embrittlement in the reactor vessel, internals, or reactor coolant system

The project team reviewed the reactor vessel, internals, and reactor coolant system AMR line items in the OCGS LRA and determined that Oyster Creek has no cast austenitic stainless steel piping that is subject to loss of fracture toughness due to thermal aging embrittlement in the reactor vessel, internals, or reactor coolant system. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.1.1, Item 3.1.1-70, the applicant stated that the AMR identifying no aging effect for stainless steel piping, piping components, and piping elements exposed to air with borated water leakage or gas in the reactor vessel, internals, and reactor coolant system is not applicable at OCGS. Oyster Creek has no stainless steel piping, piping components, or piping elements exposed to air with borated water leakage or gas in the reactor vessel, internals, or reactor coolant system

The project team reviewed the reactor vessel, internals, and reactor coolant system AMR line items in the OCGS LRA and determined that Oyster Creek has no stainless steel piping, piping components, or piping elements exposed to air with borated water leakage or gas in the reactor vessel, internals, or reactor coolant system. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.1.1, Item 3.1.1-72, the applicant stated that the AMR identifying no aging effect for steel and stainless steel piping, piping components, and piping elements in concrete in the reactor vessel, internals, and reactor coolant system is not applicable at OCGS. Oyster Creek has no steel or stainless steel piping, piping components, or piping elements in concrete in the reactor vessel, internals, or reactor coolant system.

The project team reviewed the reactor vessel, internals, and reactor coolant system AMR line items in the OCGS LRA and determined that Oyster Creek has no steel or stainless steel piping, piping components, or piping elements in concrete in the reactor vessel, internals, or reactor coolant system. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

3.1.2.3.2 Reactor Vessel, Internals, and Reactor Coolant Systems AMR Line Items That Have No Aging Effect (OCGS LRA Tables 3.1.2.1.1 Through 3.1.2.1.6)

In LRA Tables 3.1.2.1.1 through 3.1.2.1.6, the applicant identified line-items where no aging effects were identified as a result of its aging review process.

In OCGS LRA Tables 3.1.2.1.1 through 3.1.2.1.6, the applicant identified AMR line-items where no aging effects were identified as a result of its aging review process. Specifically, instances in which the applicant stated that no aging effects were identified occurred when components fabricated from stainless steel, cast austenitic stainless steel, and nickel alloy were exposed to an air-indoor uncontrolled environment.

The project team reviewed the recommendations in the GALL Report for this material/environment combination, and determined that the applicant's evaluations are consistent with the recommendations in the GALL Report. In addition, the project team reviewed the applicant's AMR technical basis documents listed in Attachment 5 of this audit and review report for the reactor vessel, internals, and reactor coolant system, and determined that no significant aging effects were identified for components with this material/environment combination.

On the basis of its review of current industry research and operating experience, the project team found that stainless steel, cast austenitic stainless steel, and nickel alloy exposed to an air-indoor uncontrolled environment will not result in aging that will be of concern during the period of extended operation. Therefore, the project team determined that there are no applicable aging effects requiring management for this material/environment combination.

Conclusion

On the basis of its review, the project team found that the applicant appropriately identified AMR results involving material, environment, aging effects requiring management, and AMP combinations that are not applicable to OCGS, and AMR results involving material and environment combinations that do not have aging effects requiring management at OCGS.

3.1.3 Conclusion

On the basis of its review, the project team determined that the applicant has demonstrated that the aging effects associated with the reactor vessel, internals, and reactor coolant system components will be adequately managed.

The project team also reviewed the applicable UFSAR supplement program summaries and concluded that they adequately describe the AMPs credited for managing aging of the reactor vessel, internals, and reactor coolant systems components, as required by 10 CFR 54.21(d).

3.2 OCGS LRA Section 3.2 – Aging Management of Engineered Safety Features

This section of the audit and review report documents the project team's review and evaluation of OCGS aging management review (AMR) results for the aging management of the engineered safety features component and component groups associated with the following systems: (1) containment spray system, (2) core spray system, and (3) standby gas treatment system.

3.2.1 Summary of Technical Information in the Application

In the OCGS LRA Section 3.2, the applicant provided the results of its AMRs for the engineered safety features components and component groups.

In OCGS LRA Table 3.2.1, ?Summary of Aging Management Engineered Safety Features," the applicant provided a summary comparison of its AMR line-items with the AMR line-items evaluated in the GALL Report for the engineered safety features components and component groups. The applicant also identified for each component type in the OCGS LRA Table 3.2.1

those AMRs that are consistent with the GALL Report, those for which the GALL Report recommends further evaluation, and those AMRs that are not addressed in the OCGS LRA together with the basis for their exclusion.

In the OCGS LRA Tables 3.2.2.1.1 through 3.2.2.1.3, the applicant provided a summary of the AMR results for component types associated with (1) containment spray system, (2) core spray system, and (3) standby gas treatment system. Specifically, the information for each component type included intended function, material, environment, aging effect requiring management, AMPs, the GALL Report Volume 2 item, cross reference to the OCGS LRA Table 3.2.1 (Table 1), and generic and plant-specific notes related to consistency with the GALL Report.

The applicant's AMRs incorporated applicable operating experience in the determination of aging effect requiring managements (AERMs). These reviews included evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.2.2 Project Team Evaluation

The project team reviewed OCGS LRA Section 3.2 to determine if the applicant provided sufficient information to demonstrate that the effects of aging for the engineered safety features components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The project team reviewed certain identified AMR line-items to confirm the applicant's claim that these AMR line-items were consistent with the GALL Report. The project team did not repeat its review of the matters described in the GALL Report. However, the project team did verify that the material presented in the OCGS LRA was applicable and that the applicant had identified the appropriate GALL Report AMR line-items. The project team's audit evaluation is documented in Section 3.2.2.1 of this audit and review report. In addition, the project team's evaluations of the AMPs are documented in Section 3.0.3 of this audit and review report.

The project team reviewed those selected AMR line-items for which further evaluation is recommended by the GALL Report. The project team confirmed that the applicant's further evaluations were in accordance with the acceptance criteria in SRP-LR. The project team's audit evaluation is documented in Section 3.2.2.2 of this audit and review report.

The project team did not review the remaining AMR line-items that were not consistent with or not addressed in the GALL Report based on NRC-approved precedents. These were reviewed by the NRR/DE staff and documented in the SER for the Oyster Creek plant.

Finally, the project team reviewed the AMP summary descriptions in the UFSAR Supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the engineered safety features components.

Table 3.2-1 below provides a summary of the project team's evaluation of components, aging effects/aging mechanisms, and AMPs listed in LRA Section 3.2 that are addressed in the GALL Report. It also includes the section of the audit and review report in which the project team's evaluation is documented. It should be noted that the line items in this table correspond to the line items in Table 3.2-1 of the September 2005 Revision 1 SRP-LR document; therefore, in many cases, they do not match the line items in Table 3.2.1 of the OCGS LRA. The SRP-LR line item number is denoted parenthetically in the column 1 entry. Also, line items that are applicable only to PWR plants are not included in this table; therefore, certain SRP-LR line item numbers do not appear in this table

Table 3.2-1 Staff Evaluation for Engineered Safety Features Components in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Steel and stainless steel piping, piping components, and piping elements in emergency core cooling system (Item 3.2.1-1)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	TLAAs were reviewed by NRR/DE staff. (See Audit Report Section 3.2.2.2.1)
Stainless steel containment isolation piping and components internal surfaces exposed to treated water (Item 3.2.1-3)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Water Chemistry (B.1.2), and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. (See Audit Report Section 3.2.2.2.3.1)
Stainless steel piping, piping components, and piping elements exposed to soil (Item 3.2.1-4)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Not applicable	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.2.3.2)
Stainless steel and aluminum piping, piping components, and piping elements exposed to treated water (Item 3.2.1-5)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Water Chemistry (B.1.2) and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. (See Audit Report Section 3.2.2.2.3.3)
Stainless steel and copper alloy piping, piping components, and piping elements exposed to lubricating oil (Item 3.2.1-6)	Loss of material due to pitting and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Not applicable	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.2.3.4)
Partially encased stainless steel tanks with breached moisture barrier exposed to raw water (Item 3.2.1-7)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated for pitting and crevice corrosion of tank bottoms because moisture and water can egress under the tank	Not applicable	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.2.3.5)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
		due to cracking of the perimeter seal from weathering.		
Stainless steel piping, piping components, piping elements, and tank internal surfaces exposed to condensation (internal) (Item 3.2.1-8)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Not applicable	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.2.3.6)
Steel, stainless steel, and copper alloy heat exchanger tubes exposed to lubricating oil (Item 3.2.1-9)	Reduction of heat transfer due to fouling	Lubricating Oil Analysis and One-Time Inspection	Not applicable	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.2.4.1)
Stainless steel heat exchanger tubes exposed to treated water (Item 3.2.1-10)	Reduction of heat transfer due to fouling	Water Chemistry and One-Time Inspection	Water Chemistry (B.1.2) and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. (See Audit Report Section 3.2.2.2.4.2)
Elastomer seals and components in standby gas treatment system exposed to air – indoor uncontrolled (Item 3.2.1-11)	Hardening and loss of strength due to elastomer degradation	A plant-specific AMP is to be evaluated.	Periodic Inspection of Ventilation Systems (B.2.4)	Consistent with GALL, which recommends further evaluation. AMP B.2.4 was reviewed by NRR/DE staff. (See Audit Report Section 3.2.2.2.5)
Steel drywell and suppression chamber spray system nozzle and flow orifice internal surfaces exposed to air – indoor uncontrolled (internal) (Item 3.2.1-13)	Loss of material due to general corrosion and fouling	A plant-specific AMP is to be evaluated.	Not applicable	Not applicable, since Oyster Creek has stainless steel spray nozzles and orifices. (See Audit Report Section 3.2.2.2.7)
Steel piping, piping components, and piping elements exposed to treated water (Item 3.2.1-14)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Water Chemistry (B.1.2) and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. (See Audit Report Section 3.2.2.2.8.1)
Steel containment isolation piping, piping components, and piping elements internal surfaces exposed to treated water (Item 3.2.1-15)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Water Chemistry (B.1.2) and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. (See Audit Report Section 3.2.2.2.8.2)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Steel piping, piping components, and piping elements exposed to lubricating oil (Item 3.2.1-16)	Loss of material due to general, pitting, and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Not applicable	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.2.8.3)
Steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil (Item 3.2.1-17)	Loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion	Buried Piping and Tanks Surveillance or Buried Piping and Tanks Inspection	Buried Piping Inspection (B.1.26)	Consistent with GALL, which recommends further evaluation. (See Audit Report Section 3.2.2.2.9)
Stainless steel piping, piping components, and piping elements exposed to treated water > 60°C (> 140°F) (Item 3.2.1-18)	Cracking due to stress corrosion cracking and intergranular stress corrosion cracking	BWR Stress Corrosion Cracking and Water Chemistry	Not applicable	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.3.1)
Steel piping, piping components, and piping elements exposed to steam or treated water (Item 3.2.1-19)	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.1.11)	Consistent with GALL. (See Audit Report Section 3.2.2.1)
Cast austenitic stainless steel piping, piping components, and piping elements exposed to treated water (borated or unborated) > 250°C (> 482°F) (Item 3.2.1-20)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS	Not applicable	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.3.1)
High-strength steel closure bolting exposed to air with steam or water leakage (Item 3.2.1-21)	Cracking due to cyclic loading, stress corrosion cracking	Bolting Integrity	Not applicable	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.3.1)
Steel closure bolting exposed to air with steam or water leakage (Item 3.2.1-22)	Loss of material due to general corrosion	Bolting Integrity	Not applicable	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.3.1)
Steel bolting and closure bolting exposed	Loss of material due to general,	Bolting Integrity	Bolting Integrity	Consistent with GALL. (See Audit Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
to air – outdoor (external), or air – indoor uncontrolled (external) (Item 3.2.1-23)	pitting, and crevice corrosion		(B.1.12)	Section 3.2.2.1)
Steel closure bolting exposed to air – indoor uncontrolled (external) (Item 3.2.1-24)	Loss of preload due to thermal effects, gasket creep, and self-loosening	Bolting Integrity	Bolting Integrity (B.1.12)	Consistent with GALL. (See Audit Report Section 3.2.2.1)
Stainless steel piping, piping components, and piping elements exposed to closed cycle cooling water > 60°C (> 140°F) (Item 3.2.1-25)	Cracking due to stress corrosion cracking	Closed-Cycle Cooling Water System	Not applicable	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.3.1)
Steel piping, piping components, and piping elements exposed to closed cycle cooling water (Item 3.2.1-26)	Loss of material due to general, pitting, and crevice corrosion	Closed-Cycle Cooling Water System	Not applicable	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.3.1)
Steel heat exchanger components exposed to closed cycle cooling water (Item 3.2.1-27)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	Not applicable	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.3.1)
Stainless steel piping, piping components, piping elements, and heat exchanger components exposed to closed-cycle cooling water (Item 3.2.1-28)	Loss of material due to pitting and crevice corrosion	Closed-Cycle Cooling Water System	Not applicable	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.3.1)
Copper alloy piping, piping components, piping elements, and heat exchanger components exposed to closed cycle cooling water (Item 3.2.1-29)	Loss of material due to pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	Not applicable	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.3.1)
Stainless steel and copper alloy heat exchanger tubes exposed to closed cycle	Reduction of heat transfer due to fouling	Closed-Cycle Cooling Water System	Not applicable	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
cooling water (Item 3.2.1-30)				Audit Report Section 3.2.2.3.1)
External surfaces of steel components including ducting, piping, ducting closure bolting, and containment isolation piping external surfaces exposed to air – indoor uncontrolled (external); condensation (external) and air – outdoor (external) (Item 3.2.1-31)	Loss of material due to general corrosion	External Surfaces Monitoring	Structures Monitoring (B.1.31)	Acceptable-The OCGS Structures Monitoring AMP is consistent with the GALL External Surfaces Monitoring AMP for this component group/ aging effect combination. (See Audit Report Section 3.2.2.1.1)
Steel piping and ducting components and internal surfaces exposed to air – indoor uncontrolled (Internal) (Item 3.2.1-32)	Loss of material due to general corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Periodic Inspection of Ventilation Systems (B.2.4)	Acceptable – The OCGS Periodic Inspection of Ventilation Systems AMP is consistent with the GALL Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP for this component group/ aging effect combination. (See Audit Report Section 3.2.2.1.1)
Steel encapsulation components exposed to air – indoor uncontrolled (internal) (Item 3.2.1-33)	Loss of material due to general, pitting, and crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Not applicable	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.3.1)
Steel piping, piping components, and piping elements exposed to condensation (internal) (Item 3.2.1-34)	Loss of material due to general, pitting, and crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Not applicable	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.3.1)
Steel containment isolation piping and components internal surfaces exposed to raw water (Item 3.2.1-35)	Loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion, and fouling	Open-Cycle Cooling Water System	Not applicable	Not Applicable since, in ESF, the drywell floor and equipment drain line is the only component subject to this aging effect, and it is managed by One-Time Inspection. (See Audit Report Section 3.2.2.1.2)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Steel heat exchanger components exposed to raw water (Item 3.2.1-36)	Loss of material due to general, pitting, crevice, galvanic, and microbiologically-influenced corrosion, and fouling	Open-Cycle Cooling Water System	Not applicable	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.3.1)
Stainless steel piping, piping components, and piping elements exposed to raw water (Item 3.2.1-37)	Loss of material due to pitting, crevice, and microbiologically-influenced corrosion	Open-Cycle Cooling Water System	Not Used in ESF Table 2 items	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.3.1)
Stainless steel containment isolation piping and components internal surfaces exposed to raw water (Item 3.2.1-38)	Loss of material due to pitting, crevice, and MIC corrosion, and fouling	Open-Cycle Cooling Water System	Not Applicable	Not Applicable since, in ESF, the drywell floor and equipment drain line is the only component subject to this aging effect and it is managed by One-Time Inspection. (See Audit Report Section 3.2.2.1.4)
Stainless steel heat exchanger components exposed to raw water (Item 3.2.1-39)	Loss of material due to pitting, crevice, and microbiologically-influenced corrosion, and fouling	Open-Cycle Cooling Water System	Not applicable	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.3.1)
Steel and stainless steel heat exchanger tubes (serviced by open-cycle cooling water) exposed to raw water (Item 3.2.1-40)	Reduction of heat transfer due to fouling	Open-Cycle Cooling Water System	Not applicable	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.3.1)
Copper alloy > 15% Zn piping, piping components, piping elements, and heat exchanger components exposed to closed cycle cooling water (Item 3.2.1-41)	Loss of material due to selective leaching	Selective Leaching of Materials	Not applicable	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.3.1)
Gray cast iron piping, piping components, piping elements exposed to closed-cycle	Loss of material due to selective leaching	Selective Leaching of Materials	Selective Leaching of Materials (B.1.25)	Consistent with GALL. (See Audit Report Section 3.2.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
cooling water (Item 3.2.1-42)			Only in Fire Protection System	
Gray cast iron piping, piping components, and piping elements exposed to soil (Item 3.2.1-43)	Loss of material due to selective leaching	Selective Leaching of Materials	Not applicable	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.3.1)
Gray cast iron motor cooler exposed to treated water (Item 3.2.1-44)	Loss of material due to selective leaching	Selective Leaching of Materials	Selective Leaching of Materials (B.1.25)	Consistent with GALL. (See Audit Report Section 3.2.2.1)
Aluminum piping, piping components, and piping elements exposed to air – indoor uncontrolled (internal/external) (Item 3.2.1-50)	None	None	None	Consistent with GALL. (See Audit Report Section 3.2.2.1)
Galvanized steel ducting exposed to air – indoor controlled (external) (Item 3.2.1-51)	None	None	None	Consistent with GALL. (See Audit Report Section 3.2.2.1)
Glass piping elements exposed to air – indoor uncontrolled (external), lubricating oil, raw water, treated water, or treated borated water (Item 3.2.1-52)	None	None	None	Consistent with GALL. (See Audit Report Section 3.2.2.1)
Stainless steel, copper alloy, and nickel alloy piping, piping components, and piping elements exposed to air – indoor uncontrolled (external) (Item 3.2.1-53)	None	None	None	Consistent with GALL. (See Audit Report Section 3.2.2.1)
Steel piping, piping components, and piping elements exposed to air – indoor controlled (external) (Item 3.2.1-54)	None	None	Not applicable	Not applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.3.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Steel and stainless steel piping, piping components, and piping elements in concrete (Item 3.2.1-55)	None	None	Not applicable	Not Applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.3.1)
Steel, stainless steel, and copper alloy piping, piping components, and piping elements exposed to gas (Item 3.2.1-56)	None	None	Not applicable	Not Applicable, since Oyster Creek has no such ESF components within the scope of license renewal. (See Audit Report Section 3.2.2.3.1)

3.2.2.1 *AMR Results That Are Consistent with The GALL Report*

Summary of Information in the Application

For aging management evaluations that the applicant stated are consistent with the GALL Report, the project team conducted its audit and review to determine if the applicant's reference to the GALL Report in the OCGS LRA was acceptable.

In OCGS LRA Section 3.2.1.2.1, the applicant identified the materials, environments, and aging effects requiring management. The applicant identified the following programs that manage the aging effects related to the containment spray system, core spray system, and standby gas treatment system components and component groups:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.1.1)
- Water Chemistry (B.1.2)
- BWR SCC (B.1.7)
- Bolting Integrity (B.1.12)
- One-Time Inspection (B.1.24)
- Selective Leaching of Materials (B.1.25)
- Buried Piping Inspection (B.1.26)
- Structures Monitoring Program (B.1.31)
- Periodic Testing of Containment Spray Nozzles (B.2.1)
- Periodic Inspection of Ventilation Systems (B.2.4)

Project Team Evaluation

The project team reviewed its assigned OCGS LRA AMR line-items to determine that the applicant (1) provides a brief description of the system, components, materials, and environment; (2) states that the applicable aging effects have been reviewed and are evaluated in the GALL Report; and (3) identifies those aging effects for the containment spray system, core spray system, and standby gas treatment system components that are subject to an AMR.

3.2.2.1.1 Loss of Material Due to General Corrosion on Internal and External Surfaces Exposed to Air and Moisture

In the OCGS LRA, Section 3.2.2.2.2, the applicant provided its further evaluation to address loss of material due to general corrosion for the internal and external surfaces of BWR steel components exposed to air and moisture, in accordance with the draft January 2005 SRP-LR.

In reviewing this further evaluation, the project team recognized that the approved September 2005 GALL Report recommended AMP XI.M36, ?External Surfaces Monitoring," or XI.M38, ?Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" to manage this aging effect with no further evaluation required. Therefore, the project team reviewed the applicant's further evaluation against the recommendations in the aforementioned GALL AMPs, as appropriate.

In the OCGS LRA, the applicant stated that Oyster Creek will use the 10CFR50 Appendix J program, B.1.29, in association with the ASME Section XI, Subsection IWE program, B.1.27, to inspect piping and fittings in the containment vacuum breaker system. The primary containment leakage rate testing program provides for aging management of pressure boundary degradation due to loss of material in systems penetrating primary containment. The primary containment inservice inspection (ISI) program utilizes inspections for degradation of accessible surface areas. Together, these programs detect degradation of the vacuum breaker system prior to the loss of intended function. Observed conditions that have the potential for impacting the intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's 10 CFR Part 50, Appendix J program (AMP B.1.29) and verified that this aging management program included activities that are consistent with the recommendations in GALL AMP XI.M36 to manage loss of material in components exposed to an indoor air internal environment. In addition, the project team reviewed the applicant's ASME Section XI ISI program (B.1.1) and verified that this aging management program includes inspections of components to detect loss of material as a means of verifying the effectiveness of the 10 CFR Part 50, Appendix J program. The project team determined that OCGS AMPs B.1.29 and B.1.1, together, will adequately manage loss of material in piping and fittings in the containment vacuum breaker system exposed to an indoor air and moisture environment.

In the OCGS LRA, the applicant stated that the periodic inspection of ventilation systems program, B.2.4, will be used to perform visual inspections of piping, piping components, piping elements, and fan and damper housings for the standby gas treatment system. Program activities include periodic visual inspections and system tests to ensure aging degradation is detected prior to loss of intended function. Observed conditions that have the potential for impacting the intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's further evaluation and determined that the periodic inspection of ventilation systems program (AMP B.2.4) is a plant specific program that is appropriate to manage the loss of material in ventilation system steel piping, piping components, and piping elements exposed to an indoor air internal or external environment. The technical evaluation of this program to determine its adequacy was performed by NRR/DE staff, and is addressed in the SER related to the Oyster Creek plant.

In the OCGS LRA, the applicant stated that the One-Time Inspection Program, B.1.24, will be used to inspect the isolation condenser shell and shell side components and the internal surfaces of carbon steel vent piping in an indoor air environment in the isolation condenser system. When not in service, portions of the isolation condenser shell and the ventilation piping contain indoor air, and inspection of the internal surfaces verifies that unacceptable degradation is not occurring and that the component intended function will be maintained during the extended period of operation. Observed conditions that have the potential for impacting the intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's One-Time Inspection Program (AMP B.1.24) and verified that this aging management program included activities that are consistent with the recommendations in GALL AMP XI.M38 to manage loss of material in components exposed to an indoor air internal environment. The project team determined that OCGS AMP B.1.24 will adequately manage loss of material in the isolation condenser components exposed to an air environment.

In the OCGS LRA, the applicant further stated that the structures monitoring program, B.1.31, will be used to inspect the external surfaces of steel piping, piping components, piping elements, and ducting in an indoor air or outdoor air environment for the containment spray system, core spray system, standby gas treatment system, containment vacuum breakers system, isolation condenser system, post-accident sampling system, and drywell floor and equipment drains system when there are no other AMPs that inspect the items. The structures monitoring program directs periodic visual inspections to identify and evaluate the degradation of the inspected items to ensure that there is no loss of intended function. Observed conditions that have the potential for impacting the intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's structures monitoring program (AMP B.1.31) and verified that this aging management program included activities that are consistent with GALL AMP XI.M36 to manage the loss of material in components exposed to an indoor or outdoor air external environment. The project team determined that OCGS AMP B.1.31 will adequately manage the loss of material on the external surfaces of steel piping, piping components, piping elements, and ducting in an indoor air or outdoor air environment for the containment spray system, core spray system, standby gas treatment system, containment vacuum breakers system, isolation condenser system, post-accident sampling system, and drywell floor and equipment drains system .

Finally, in the OCGS LRA, the applicant stated that the external surfaces of the reactor pressure vessel nozzles in an environment of containment atmosphere do not require an aging management program. The aging effect of loss of material due to general corrosion in the primary containment atmosphere does not need to be considered for carbon steel components in a containment nitrogen environment because of negligible amounts of free oxygen (less than 4 percent by volume during normal operation). Both oxygen and moisture must be present for general corrosion to occur because oxygen alone or water free of dissolved oxygen (high humidity in a nitrogen atmosphere) does not corrode carbon steel to any practical extent. Therefore, there is no loss of material for carbon steel components exposed to a containment nitrogen environment because, with the negligible amounts of free oxygen, anodic reactions do not take place and the corrosion cell does not form.

The project team reviewed the applicant's further evaluation related to loss of material due to general corrosion in the primary containment atmosphere for carbon steel components and concurred with the applicant's conclusion that this is not a credible aging effect. The Oyster Creek containment is inerted during normal operation; therefore, there are negligible amounts of free oxygen present. Since oxygen and moisture must be present for general corrosion to occur, general corrosion of carbon steel components is not a credible event.

On the basis of its review, the project team found that the applicant appropriately addressed the aging effect/mechanism, as recommended by the GALL Report.

3.2.2.1.2 Loss of Material Due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion Steel Containment Isolation Components Exposed Internally to Untreated Water

In the OCGS LRA, Section 3.2.2.2.4, the applicant provided its further evaluation to address loss of material due to general, pitting, crevice, and MIC for steel BWR containment isolation piping, piping components, and piping elements exposed internally to untreated water in systems that are not addressed in other chapters of the GALL Report.

In the OCGS LRA, the applicant stated that Oyster Creek will use the One-Time Inspection Program, B.1.24, to manage the loss of material in the steel portion of drywell floor and equipment drains system piping that provides the containment isolation barrier. The program elements include determination of appropriate inspection sample size, identification of inspection locations, selection of examination techniques with acceptance criteria, and evaluation of results. Observed conditions that have the potential for impacting the intended function are evaluated or corrected in accordance with the corrective action process.

The applicant was asked to justify how the One-Time Inspection Program would manage the containment isolation component surfaces that are exposed to untreated or raw water. In its response, the applicant stated that aging effects of the drywell floor and equipment drains system piping providing a containment isolation function are managed with the structures monitoring program for external surfaces, and the One-Time Inspection Program for internal surfaces. The One-Time Inspection Program confirms the absence of aging effects in pooled or potentially stagnant flow areas of drain piping and piping elements. The water in reactor building floor drain sump consists primarily of formerly treated water source from containment systems. This relatively high quality water, along with a lack of operating experience citing age-related issues with this piping indicated that a one-time inspection program was appropriate for ensuring the piping and components will perform their intended function during the period of extended operation. Any observed conditions that have the potential for impacting the intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant’s response and determined that the One-Time Inspection Program would be adequate to monitor the internal surfaces of the drywell floor and equipment drains system since the water in the reactor building floor drain sump consists primarily of formerly treated water from the containment systems. This relatively high quality water is not expected to cause significant aging effects, which is supported by plant operating experience.

On the basis of its review, the project team found that the applicant appropriately addressed the aging effect/mechanism, as recommended by the GALL Report.

3.2.2.1.3 General, Pitting, Crevice, and Microbiologically Influenced Corrosion and Fouling in Stainless Steel Containment Isolation Component Exposed to Raw or Untreated Water

In the OCGS LRA, Section 3.2.2.2.7.1, the applicant provided its further evaluation to address loss of material due to pitting, crevice and MIC, and fouling for the internal surfaces of stainless steel containment isolation piping, piping components, and piping elements in contact with raw or untreated water.

In the OCGS LRA, the applicant stated that Oyster Creek will use the One-Time Inspection Program, B.1.24, to evaluate for loss of material of the stainless steel portion of drywell floor and equipment drains system piping that provides the containment isolation barrier. The program elements include determination of appropriate inspection sample size, identification of inspection locations, selection of examination techniques with acceptance criteria, and evaluation of results. Observed conditions that have the potential for impacting the intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's One-Time Inspection Program (AMP B.1.24) and verified that this aging management program included activities that are adequate to manage loss of material for the stainless steel portion of drywell floor and equipment drains system piping that provides containment isolation barrier and is exposed to raw or untreated water. The project team noted that, while the environment is stated to be raw or untreated water, it is actually formerly treated water that is likely still of high quality. Therefore, the project team determined that OCGS AMP B.1.24 will adequately manage loss of material due to pitting, crevice and MIC, and fouling for the internal surfaces of stainless steel containment isolation piping, piping components, and piping elements in contact with raw or untreated water.

On the basis of its review, pending satisfactory resolution of the open issue, the project team found that the applicant appropriately addressed the aging effect/mechanism, as recommended by the GALL Report.

3.2.2.1.4 General, Pitting, Crevice, and Microbiologically Influenced Corrosion and Fouling in Steel Containment Isolation Component Exposed to Raw Water

In the OCGS LRA, Section 3.2.2.2.7.2 the applicant provided its further evaluation to address loss of material due to general, pitting, crevice and MIC and fouling that could occur for steel containment isolation piping, piping components, and piping elements in contact with raw water.

In the OCGS LRA, the applicant stated that this Item number is not used at Oyster Creek. Item Number 3.2.1-5 discussed in 3.2.2.2.4 above addresses loss of material for steel components in an untreated water environment due to pitting, crevice and MIC, and fouling, and was used for Oyster Creek components in lieu of Item Number 3.2.1-9.

The project team reviewed Section 3.2.2.2.4 in the OCGS LRA and found that this aging effect/mechanism is similar to that discussed above in Section 3.2.2.2.4 for untreated water. Therefore, the project team determined that the applicant's use of the AMR associated with the further evaluation presented in Section 3.2.2.2.4 of the OCGS LRA in lieu of this further evaluation is acceptable.

3.2.2.1.5 Loss of Material Due to General Corrosion of External Surface of Carbon and Low Alloy Steel Components

In LRA Tables 3.2.2.2.1 for the containment spray system, 3.2.2.2.2 for the core spray system, and Table 3.2.2.2.3 for the standby gas treatment system, the applicant proposed to manage loss of material for the external surfaces of carbon and low alloy steel components exposed to an air environment using the OCGS structures monitoring program (AMP B.1.31). However, the project team noted that the GALL Report recommends the external surfaces monitoring program (AMP XI.M36) to manage this aging effect.

The project team reviewed the applicant's structures monitoring program (AMP B.1.31) and verified that this aging management program included activities that are consistent with GALL AMP XI.M36 to manage the loss of material in components exposed to an air external environment. The project team determined that OCGS AMP B.1.31 will adequately manage the loss of material on the external surfaces of carbon and low alloy steel components exposed to an air external environment in the engineered safety features systems.

On the basis of its review, the project team found that the applicant appropriately addressed the loss of material due to general corrosion for external surfaces of carbon and low alloy steel components.

3.2.2.1.6 Loss of Material Due to General, Pitting and Crevice Corrosion

3.2.2.1.6.1 Loss of Material due to General, Pitting and Crevice Corrosion [Item 1]

In the OCGS LRA, Section 3.2.2.2.8.2, the applicant provided its further evaluation for loss of material due to general, pitting, and crevice corrosion for steel components in the engineered safety features systems exposed to condensation, treated water, or air-indoor uncontrolled, in accordance with the draft January 2005 SRP-LR.

In the OCGS LRA, the applicant stated that the Oyster Creek engineered safety features systems have no steel piping, piping components, or piping elements (internal surfaces) exposed to condensation, treated water, or air-indoor uncontrolled environments.

The project team noted that the containment isolation system at Oyster Creek includes steel components that are exposed to treated water on the internal surface. Therefore, the applicant was asked to clarify the credited AMPs for loss of material due to general, pitting and crevice corrosion in steel piping, piping components, and piping elements in contact with treated water, and to clarify the discrepancy in the statement, ?Oyster Creek Engineered Safety Features Systems have no steel piping, piping components, or piping elements (internal surfaces) exposed to condensation, treated water, or air-indoor uncontrolled environments."

In its response, the applicant stated that the Oyster Creek LRA used line item 3.2.1-10 (E-08) and associated further evaluation section 3.2.2.2.8.1 for steel piping in contact with treated water in the engineered safety features (ESF) systems. In the GALL Report, this line item invoked the water chemistry and one-time inspection programs with further evaluation recommended, and was clearly the applicable choice for managing aging effects in water-carrying process piping for the ESF systems. Line item 3.2.1-10 was only used for Oyster Creek as related item E-40 for steel closure bolting in the standby gas treatment system. In the January 2005 draft GALL, this line item specifies a plant specific program for aging management.

The applicant also stated that the statement in the associated further evaluation Section 3.2.2.2.8.2 for item 3.2.1-10 (that the ESF systems have no carbon steel piping, piping components, or piping elements (internal surfaces) exposed to condensation, treated water, or air-indoor uncontrolled environments) was made within the context of this line item's application to a wetted-air internal environment, and was not used for the steel piping lines of the ESF systems. "Treated Water" was included to match the wording in Section 3.2.2.2.8.2 of the draft January 2005 SRP-LR. To correct this discrepancy, this statement will be revised in a supplement document.

In its letter dated April 17, 2006 (ML061150320), the applicant committed to revise the further evaluation in Section 3.2.2.2.8.2 of the OCGS LRA to state that Oyster Creek engineered safety features systems have no steel piping, piping components, or piping elements (internal surfaces) exposed to condensation, treated water (in the form of condensation wetting the internal surface), or air-indoor uncontrolled environments. **This is Audit Commitment 3.2.2.1.6-1.**

The project team reviewed Tables 3.2.2.1.1, 3.2.2.1.2, and 3.2.2.1.3 in the OCGS LRA for the ESF systems and confirmed that no steel components exposed to condensation are identified. Therefore, the project team found that the applicant's commitment to revise the further evaluation in Section 3.2.2.2.8.2 of the OCGS LRA is acceptable.

On the basis of its review, the project team found that the applicant appropriately addressed the loss of material due to general, pitting and crevice corrosion for internal surfaces of carbon and low alloy steel components.

3.2.2.1.6.2 Loss of Material due to General, Pitting and Crevice Corrosion [Item 2]

In the OCGS LRA, Table 3.2.2.1.3 for the standby gas treatment system includes AMR line items for loss of material due to general, pitting, and crevice corrosion of steel bolting exposed to air with steam or water leakage. The applicant proposed to manage this aging effect using the OCGS structures monitoring program (AMP B.1.31). Generic note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report; however, a different aging management program was credited. The GALL Report recommended the Bolting Integrity Program (AMP XI.M18).

The project team reviewed the applicant's structures monitoring program (AMP B.1.31) and determined that it is consistent with the recommendations in the Bolting Integrity Program (XI.M18) recommended by the GALL Report for this aging effect. On this basis, the project team determined that the program credited to manage loss of material of the steel bolting is appropriate.

On the basis of its review, the project team found that the applicant appropriately addressed loss of material due to general, pitting, and crevice corrosion for steel bolting exposed to air with steam or water leakage in the engineered safety features systems.

Conclusion

The project team has evaluated the applicant's claim of consistency with the GALL Report. The project team also has reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the project team found that the AMR results, which the applicant claimed to be consistent with the GALL Report, are consistent with the AMRs in the GALL Report.

3.2.2.2 *AMR Results For Which Further Evaluation Is Recommended By The GALL Report*

Summary of Information in the Application

In OCGS LRA Section 3.2.2.2, the applicant provided further evaluation of aging management as recommended by the GALL Report for the aging effects related to the containment spray system, core spray system, and standby gas treatment system components and component groups. The applicant also provided information concerning how it will manage the related aging effects.

Project Team Evaluation

For some AMR line-items assigned to the project team in the OCGS LRA Tables 3.2.1, the GALL Report recommends further evaluation. When further evaluation is recommended, the project team reviewed these further evaluations provided in OCGS LRA Section 3.2.2.2 against the criteria provided in the SRP-LR Section 3.2.2.2. The project team's assessments of these evaluations are documented in this section. These assessments are applicable to each Table 2 AMR line-item in Section 3.2 citing the item in Table 1.

3.2.2.2.1 Cumulative Fatigue Damage

In LRA Section 3.2.2.2.1, the applicant stated that fatigue is a TLAA, as defined in 10 CFR 54.3. Applicants must evaluate TLAAs in accordance with 10 CFR 54.21(c)(1). The evaluation of the TLAAs was performed by NRR/DE staff and is addressed separately in Section 4 of the SER related to the OCGS LRA.

3.2.2.2.2 Loss of Material due to Cladding

Loss of material due to cladding breach could occur for PWR steel pump casings with stainless steel cladding exposed to treated borated water. The staff concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek is a BWR plant.

3.2.2.2.3 Loss of Material Due to Pitting and Crevice Corrosion

3.2.2.2.3.1 Loss of Material due to Pitting and Crevice Corrosion [Item 1]

The project team reviewed OCGS LRA Section 3.2.2.2.3.1 against the criteria in SRP-LR Section 3.2.2.2.3.1.

SRP-LR Section 3.2.2.2.3.1 stated that loss of material due to pitting and crevice corrosion could occur for internal surfaces of stainless steel containment isolation piping, piping components, and piping elements exposed to treated water. The existing AMP relies on monitoring and control of water chemistry to mitigate degradation. However, control of water chemistry does not preclude loss of material due to pitting and crevice corrosion at locations of stagnant flow conditions. Therefore, the effectiveness of the chemistry control program should be verified to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to verify the effectiveness of the chemistry control program. A one-time inspection of select components at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or an aging effect is progressing very slowly such that the component's intended function will be maintained during the period of extended operation.

In the OCGS LRA Section 3.2.2.2.3.1, the applicant stated that Oyster Creek will use the Water Chemistry Program, B.1.2, to manage aging of stainless steel piping and components exposed to treated in the containment spray system, containment vacuum breakers system, condensate transfer system, core spray system, isolation condenser system, nuclear boiler instrumentation system, post-accident sampling system, and reactor recirculation system. The program activities provide for monitoring and controlling of water chemistry using station procedures and processes for the prevention or mitigation of loss of material aging effects. The One-Time Inspection Program, B.1.24, will be used in each of these systems for verification of chemistry control and confirmation of the absence of loss of material. Observed conditions that have the potential for impacting the intended function are evaluated or corrected in accordance with the corrective action process.

The applicant further stated that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program, B.1.1, will be used to inspect the isolation condenser stainless steel tubes and tube side components to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period of operation. Observed conditions that have the potential for impacting the intended function are evaluated or corrected in accordance with the corrective action process.

The applicant was asked to clarify which AMPs are credited for managing loss of material due to pitting and crevice corrosion in stainless steel components of the containment isolation system exposed to treated water. In its response, the applicant stated that the September 2005 Revision 1 SRP-LR changed line item E-33 to apply specifically to Stainless steel (SS) containment isolation piping in a treated water environment, and now specifies Water Chemistry and One-Time Inspection as the AMPs to be used, in lieu of a plant-specific program as specified in the January 2005 draft SRP-LR. The Oyster Creek LRA specifies this same line item E-33 for SS piping and components in a treated water environment, and lists the Water Chemistry and One-Time Inspection AMPs, in accordance with the September 2005 Revision 1 SRP-LR. Line Item EP-32 is also used in the Oyster Creek LRA for loss of material due to pitting and crevice corrosion in SS piping and components in containment isolation piping in a treated water environment. This line item, which specified plant-specific programs in the January 2005 draft SRP-LR and now specifies Water Chemistry and One-Time Inspection Programs in the September 2005 Revision 1 SRP-LR, is used at Oyster Creek with the AMPs of Water Chemistry and One-Time Inspection, in accordance with the SRP-LR. Thus, this is consistent with the SRP-LR recommendations.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.2.2.2.3.1 for further evaluation.

3.2.2.2.3.2 <u>Loss of Material due to Pitting and Crevice Corrosion [Item 2]</u>

The project team reviewed OCGS LRA Section 3.2.2.2.3.2 against the criteria in SRP-LR Section 3.2.2.2.3.2.

SRP-LR Section 3.2.2.2.3.2 stated that loss of material from pitting and crevice corrosion could occur for stainless steel piping, piping components, and piping elements exposed to soil. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that the aging effect is adequately managed.

In the OCGS LRA Section 3.2.2.2.3.2, the applicant stated that the AMR associated with this further evaluation is not used at Oyster Creek. The engineered safety features systems have no stainless steel piping, piping components or piping elements in contact with soil, untreated, or raw water (including internal condensation). Oyster Creek has no external or partially encased stainless steel tanks in the scope of license renewal.

The project team reviewed the AMR line items for the engineered safety feature systems and verified that no stainless steel piping, piping components or piping elements in contact with soil, untreated, or raw water (including internal condensation) were identified as being within the scope of license renewal. Therefore, the project team concurred with the applicant's conclusion that this AMR is not applicable to Oyster Creek.

3.2.2.2.3.3 Loss of Material due to Pitting and Crevice Corrosion [Item 3]

The applicant addressed the further evaluation for loss of material due to pitting and crevice corrosion for stainless steel piping, piping components, and piping elements exposed to treated water in LRA Section 3.2.2.2.3.1, in accordance with the draft January 2005 SRP-LR. Therefore The project team reviewed OCGS LRA Section 3.2.2.2.3.1 against the criteria in SRP-LR Section 3.2.2.2.3.3.

SRP-LR Section 3.2.2.2.3.3 stated that loss of material from pitting and crevice corrosion could occur for BWR stainless steel and aluminum piping, piping components, and piping elements exposed to treated water. The existing AMP relies on monitoring and control of water chemistry for BWRs to mitigate degradation. However, control of water chemistry does not preclude loss of material due to pitting and crevice corrosion at locations of stagnant flow conditions. Therefore, the effectiveness of the chemistry control program should be verified to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to verify the effectiveness of the water chemistry control program. A one-time inspection of select components at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or an aging effect is progressing very slowly such that the component's intended function will be maintained during the period of extended operation.

In the OCGS LRA, Section 3.2.2.2.3.1, the applicant stated that the Water Chemistry Program (AMP B.1.2) and the One-Time Inspection Program (AMP B.1.24) will be used to manage this aging effect. The project team's evaluation of OCGS LRA Section 3.2.2.2.3.1 for BWR stainless steel piping, piping components, and piping elements exposed to treated water is discussed in Section 3.2.2.2.3.1 of this audit and review report.

The project team noted that the applicant did not provide a further evaluation for aluminum piping exposed to treated. The project team reviewed the AMR line items in Tables 3.2.2.1.1, 3.2.2.1.2, and 3.2.2.1.3 in the OCGS LRA and determined that there is no aluminum piping exposed to treated water in the engineered safety features systems. Therefore, there was no need to perform a further evaluation for this material.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.2.2.2.3.3 for further evaluation.

3.2.2.2.3.4 Loss of Material due to Pitting and Crevice Corrosion [Item 4]

The project team noted that the applicant did not credit the GALL Report AMR for loss of material due to pitting and crevice corrosion for stainless steel and copper alloy piping, piping components, and piping elements exposed to lubricating oil, which is associated with this further evaluation, for the Oyster Creek engineered safety features systems. This was a new AMR that was not in the draft January 2005 GALL Report.

The applicant was asked to clarify which AMPs are credited for loss of material from pitting and crevice corrosion for stainless steel and copper alloy piping, piping components, and piping elements exposed to lubricating oil in the engineered safety features systems.

In its response, the applicant stated that line items EP-45 and EP-51, addressed in the September 2005 Revision 1 SRP-LR, Section 3.2.2.2.3.4, are new line items that were not contained in the January 2005 draft SRP-LR used in preparing the Oyster Creek LRA. This MEA combination is not present in ESF systems at Oyster Creek. The Oyster Creek LRA addresses loss of material in SS in a lubricating oil environment for other systems with line items AP-59 (LRA Section 3.3.2.2.12.2) and SP-38 (LRA Section 3.4.2.2.8).

The applicant further stated that, for ESF systems, Oyster Creek LRA Table item 3.2.1-34 (EP-21) indicates no aging effect for SS piping, piping components, and piping elements in a lubricating oil environment. This is consistent with the January 2005 draft SRP, Table 3.2-1 item 34. However, since this material/environment is not present in the Oyster Creek ESF systems, LRA Table 3.2.1, Item 3.2.1-34 will be revised to state that the MEA combination is not applicable to the Oyster Creek ESF systems.

In its letter dated April 17, 2006 (ML061150320), the applicant committed to revise OCGS LRA Table 3.2.1, line item 3.2.1-34 related to stainless steel piping, piping components, and piping elements exposed to lubricating oil in the engineered safety features systems to state that this material/environment combination is not applicable to Oyster Creek. **This is Audit Commitment 3.2.2.2.3-1.**

The project team reviewed the AMR line items in Tables 3.2.2.1.1, 3.2.2.1.2, and 3.2.2.1.3 in the OCGS LRA for the ESF systems, and verified that no stainless steel or copper alloy components exposed to lubricating oil are present in ESF systems at Oyster Creek. Therefore, the project team found the applicant's commitment acceptable, and this further evaluation is not applicable to Oyster Creek.

3.2.2.2.3.5 Loss of Material due to Pitting and Crevice Corrosion [Item 5]

The applicant addressed loss of material due to pitting and crevice corrosion for partially encased stainless steel tanks in Section 3.2.2.2.3.2 of the OCGS LRA, in accordance with the draft January 2005 SRP-LR. Therefore, the project team reviewed Section 3.2.2.2.3.2 of the OCGS LRA against the criteria in SRP-LR Section 3.2.2.2.3.5.

SRP-LR Section 3.2.2.2.3.5 stated loss of material from pitting and crevice corrosion could occur for of partially encased stainless steel tanks exposed to raw water due to cracking of the perimeter seal from weathering. The GALL Report recommends further evaluation to ensure that the aging effect is adequately managed. The GALL Report recommends that a plant-specific AMP be evaluated because moisture and water can egress under the tank if the perimeter seal is degraded

In the OCGS LRA, the applicant stated that the Oyster Creek engineered safety features systems have no stainless steel piping, piping components or piping elements in contact with soil, untreated, or raw water (including internal condensation). Oyster Creek has no external or partially encased stainless steel tanks in the scope of license renewal.

The project team reviewed the AMR line items in OCGS LRA Tables 3.2.2.1.1, 3.2.2.1.2, and 3.2.2.1.3 for the ESF systems and confirmed that the Oyster Creek engineered safety features systems have no stainless steel piping, piping components or piping elements in contact with soil, untreated, or raw water (including internal condensation). Therefore, the project team concurred with the applicant's conclusion that this further evaluation is not applicable to Oyster Creek.

3.2.2.2.3.6 Loss of Material due to Pitting and Crevice Corrosion [Item 6]

The applicant addressed loss of material due to pitting and crevice corrosion for partially encased stainless steel tanks in Section 3.2.2.2.3.2 of the OCGS LRA, in accordance with the draft January 2005 SRP-LR. Therefore, the project team reviewed Section 3.2.2.2.3.2 in the OCGS LRA against the criteria in SRP-LR Section 3.2.2.2.3.6.

SRP-LR Section 3.2.2.2.3.6 stated that loss of material from pitting and crevice corrosion could occur for stainless steel piping, piping components, piping elements, and tanks exposed to internal condensation. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that the aging effect is adequately managed

In the OCGS LRA, the applicant stated that the Oyster Creek engineered safety features systems have no stainless steel piping, piping components or piping elements in contact with soil, untreated, or raw water (including internal condensation). Oyster Creek has no external or partially encased stainless steel tanks in the scope of license renewal.

The project team reviewed the AMR line items in OCGS LRA Tables 3.2.2.1.1, 3.2.2.1.2, and 3.2.2.1.3 for the ESF systems and confirmed that the Oyster Creek engineered safety features systems have no stainless steel piping, piping components or piping elements in contact with soil, untreated, or raw water (including internal condensation). Therefore, the project team concurred with the applicant's conclusion that this further evaluation is not applicable to Oyster Creek.

3.2.2.2.4 Reduction of Heat Transfer Due to Fouling

3.2.2.2.4.1 Reduction of Heat Transfer due to Fouling [Item 1]

The project team noted that the applicant did not credit the GALL Report AMR for reduction of heat transfer due to fouling for stainless steel and copper alloy heat exchanger tubes exposed to lubricating oil, which is associated with this further evaluation, for the Oyster Creek engineered safety features systems. This was a new AMR that was not in the draft January 2005 GALL Report.

The applicant was asked to clarify which AMPs are credited for reduction of heat transfer due to fouling for steel, stainless steel, and copper alloy heat exchanger tubes exposed to lubricating oil in the engineered safety features systems. In its response, the applicant stated that the September 2005 Revision 1 SRP, Section 3.2.2.2.4.1, addresses line items EP-40, EP-47, and EP-50, which are all new line items and were not included in the January 2005 draft SRP. Consequently, these items were not used in the Oyster Creek LRA. This MEA combination is not present in ESF systems at Oyster Creek. The Oyster Creek LRA used the lubricating oil monitoring activities (B.2.2) program for reduction of heat transfer in aluminum heat exchanger fins, cast iron bearing cooler housings, and copper alloy heat exchanger tubes exposed to a lubricating oil environment in the EDG, RBCCW, and fire protection systems. The January 2005 draft SRP did not contain these MEA combinations, therefore plant-specific notes were applied to these line items.

The project team reviewed the AMR line items in OCGS LRA Tables 3.2.2.1.1, 3.2.2.1.2, and 3.2.2.1.3 for the ESF systems and confirmed that the Oyster Creek engineered safety features systems have no stainless steel or copper alloy heat exchanger tubes exposed to lubricating oil. Therefore, the project team concurred with the applicant's conclusion that this further evaluation is not applicable to Oyster Creek.

3.2.2.2.4.2 Reduction of Heat Transfer due to Fouling [Item 2]

The applicant addressed reduction of heat transfer due to fouling for stainless steel heat exchanger tubes exposed to treated water in Attachment 3, Item EP-34 of its reconciliation of the AMPs in the draft January 2005 GALL Report to the approved September 2005 GALL Report. The project team reviewed the applicant's further evaluation against the criteria in SRP-LR Section 3.2.2.2.4.2.

SRP-LR Section 3.2.2.2.4.2 stated that reduction of heat transfer due to fouling could occur for stainless steel heat exchanger tubes exposed to treated water. The existing program relies on control of water chemistry to manage reduction of heat transfer due to fouling. However, control of water chemistry may have been inadequate. Therefore, the GALL Report recommends that the effectiveness of the chemistry control program should be verified to ensure that reduction of heat transfer due to fouling is not occurring. A one-time inspection is an acceptable method to ensure that reduction of heat transfer is not occurring and that the component's intended function will be maintained during the period of extended operation.

In Attachment 3, Item EP-34 of its reconciliation document, the applicant stated that the line item for stainless steel heat exchanger tubes in treated water, addressing reduction of heat transfer due to fouling, invoked the Water Chemistry Program with no further evaluation required in the draft January 2005 GALL Report. This has been changed in the September 2005 GALL Report to water chemistry and one-time inspection, with an evaluation of aging effects required. There are 2 instances of this line item being used in the Oyster Creek license renewal application, both in the isolation condenser system, for heat exchanger tubes, internal and external.

The applicant further stated that, in the Oyster Creek LRA, there are 132 line item instances of one-time inspection of stainless steel components in a treated water environment. While these instances are applied to aging effects of loss of material or cracking, they provide ample inspection opportunity for the condition of the components – observed conditions that have the potential for impacting an intended function are evaluated and corrected as necessary in accordance with the corrective action process. Since one of the functions of the Water Chemistry Program is to prevent or mitigate reduction of heat transfer due to fouling, a detected fouling condition on any of the components inspected for loss of material or cracking would also be identified and entered into the corrective action process. Thus, there is high confidence that any instance of the water chemistry program's failure to prevent fouling would be identified during the inspections for loss of material due to corrosion and cracking. However, since the isolation condenser tubes specifically will undergo eddy current testing during the first ten years of the period of extended operation, a one-time inspection for fouling of the internal surface of the tubes can be performed at that time. The isolation condenser shell side components undergo inspection for loss of material under the One-Time Inspection Program; an inspection of the external surface of the tubes for reduction of heat transfer due to fouling will also be performed.

In its letter dated March 30, 2006 (ML060950408), the applicant committed to revise OCGS LRA Table 3.1.2.1.1 for the isolation condenser system to include two new line items invoking one-time inspection to supplement the Water Chemistry Program for reduction of heat transfer due to fouling for the internal and external surfaces of the isolation condenser heat exchanger tubes. These are new additions based on the reconciliation of the Oyster Creek LRA between the January 2005 draft GALL and the approved September 2005 Revision 1 GALL. **This is Audit Commitment 3.2.2.2.4-1.**

The project team found that based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.2.2.2.4.2 for further evaluation.

3.2.2.2.5 Hardening and Loss of Strength Due to Elastomer Degradation

The project team reviewed OCGS LRA Section 3.2.2.2.5 against the criteria in SRP-LR Section 3.2.2.2.5.

SRP-LR Section 3.2.2.2.5 stated that hardening and loss of strength due to elastomer degradation could occur in elastomer seals and components associated with the BWR Standby Gas Treatment System ductwork and filters exposed to air-indoor uncontrolled. The GALL Report recommends further evaluation of a plant specific AMP to ensure that the aging effect is adequately managed.

In the OCGS LRA Section 3.2.2.2.5, the applicant stated that Oyster Creek will use the periodic inspection of ventilation systems program, B.2.4, to evaluate elastomer door seals and flexible connections in the standby gas treatment system. Periodic inspections are performed on elastomer door seals and flexible connections to identify leakage or detrimental changes in material properties, as evidenced by cracking, perforations in the material. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The applicant was asked to confirm that door seals and flexible connections are the only components in this system with elastomer seals. In its response, the applicant stated that regularly opened door seals and flexible connections at the fans are the only elastomers requiring aging management in the standby gas treatment system. Installed gaskets, component seals and o-rings are considered consumables not subject to an AMR, see LRA Section 2.1.6.4. The bi-weekly SGTS surveillance test, see PBD-AMP-B.2.04, Table 5.1, confirms proper function of each SGTS train with acceptance criteria for flow rate and reactor building differential pressure.

The applicant further stated that LRA Section 2.1.6.4 states "The evaluation process for consumables is consistent with the guidance provided in NUREG-1800 Table 2.1-3. Consumables have been divided into the following four categories for the purpose of license renewal: (a) packing, gaskets, component seals, and O-rings; (b) structural sealants; (c) oil, grease, and component filters; and (d) system filters, fire extinguishers, fire hoses, and air packs. Group (a) subcomponents (packing, gaskets, seals, and O-rings): Based on ANSI B31.1 and the ASME Code Section III, the subcomponents of pressure retaining components as shown above are not pressure-retaining parts. Therefore, these subcomponents are not relied on to form a pressure-retaining function and are not subject to an AMR."

The project team reviewed the applicant's further evaluation and determined that the periodic inspection of ventilation systems program (AMP B.2.4) is a plant specific program that is appropriate to detect hardening and loss of strength of elastomer seals and components. The technical evaluation of this program to determine its adequacy was performed by NRR/DE staff, and is addressed in the SER related to the Oyster Creek plant.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.2.2.2.5 for further evaluation.

3.2.2.2.6 Loss of Material Due to Erosion

In Section 3.2.2.2.6 of the OCGS LRA, the applicant stated that loss of material due to erosion of the PWR HPSI pump mini flow orifice is applicable to PWRs only. The project team concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek is a BWR plant.

3.2.2.2.7 Loss of Material Due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion, and Fouling

The applicant addressed loss of material due to general, pitting, crevice, and MIC for steel drywell and suppression chamber spray system nozzles in Section 3.2.2.2.9 of the OCGS LRA, in accordance with the draft January 2005 SRP-LR. Therefore, the project team reviewed OCGS LRA Section 3.2.2.2.9 against the criteria in SRP-LR Section 3.2.2.2.7.

SRP-LR Section 3.2.2.2.7 stated that loss of material due to general corrosion and fouling can occur for steel drywell and suppression chamber spray system nozzle and flow orifice internal surfaces exposed to air – indoor uncontrolled. This could result in plugging of the spray nozzles and flow orifices. This aging mechanism and effect will apply since the spray nozzles and flow orifices are occasionally wetted, even though the majority of the time this system is on standby. The wetting and drying of these components can accelerate corrosion and fouling. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that the aging effect is adequately managed.

In OCGS LRA Section 3.2.2.2.9, the applicant stated that the AMR associated with this further evaluation is not used at Oyster Creek since the containment spray nozzle and orifice assemblies used at Oyster Creek are stainless steel.

The project team reviewed the AMR line items in Tables 3.2.2.1.1, 3.2.2.1.2, and 3.2.2.1.3 in the OCGS LRA for the engineered safety features and verified that the containment spray nozzle and orifice assemblies used at Oyster Creek are stainless steel; not steel. Therefore, the project team concurred with the applicant's conclusion that this further evaluation is not applicable to Oyster Creek.

3.2.2.2.8 Loss of Material Due to General, Pitting and Crevice Corrosion

3.2.2.2.8.1 Loss of Material due to General, Pitting and Crevice Corrosion [Item 1]

The project team reviewed OCGS LRA Section 3.2.2.2.8.1 against the criteria in SRP-LR Section 3.2.2.2.8.1.

SRP-LR Section 3.2.2.2.8.1 stated that loss of material due to general, pitting and crevice corrosion could occur for BWR steel piping, piping components, and piping elements exposed to treated water. The existing AMP relies on monitoring and control of water chemistry for BWRs to mitigate degradation. However, control of water chemistry does not preclude loss of material due to general, pitting, and crevice corrosion at locations of stagnant flow conditions. Therefore, the effectiveness of the chemistry control program should be verified to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to verify the effectiveness of the water chemistry control program. A one-time inspection of select components at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or an aging effect is progressing very slowly such that the component's intended function will be maintained during the period of extended operation.

In the OCGS LRA Section 3.2.2.2.8.1, the applicant stated that Oyster Creek will use the Water Chemistry Program, B.1.2, to manage aging of steel piping, piping components, and piping elements exposed to a treated water environment in the containment spray system, core spray system, isolation condenser system, post-accident sampling system, and reactor pressure vessel. The program activities provide for monitoring and controlling of water chemistry using station procedures and processes for the prevention or mitigation of loss of material aging effects. The One-Time Inspection Program, B.1.24, will be used in each of these systems for verification of chemistry control and confirmation of the absence of loss of material. The periodic inspection of containment spray nozzles program, B.2.1, will also be used to manage corrosion of steel piping and piping components in the containment spray system. Observed conditions that have the potential for impacting the intended function are evaluated or corrected in accordance with the corrective action process.

The project team noted in the AMR technical basis document, OC-AMR-2.3.2.2 for the containment spray system, that the applicant has credited the periodic testing of containment spray nozzles AMP (B.2.1) to manage plugging by rust from carbon steel piping components in the containment (drywell and torus) spray system. In accordance with the OCGS AMP B.2.1, the periodic containment spray nozzle flow testing is performed every fifth refueling outage. The AMP also stated that the OCGS containment spray nozzles are stainless steel, and there are no carbon steel flow orifices in the system piping. However, the upstream carbon steel piping is subject to general corrosion. From the operating experience, it was noted that during the last test in 2000, two nozzles did indicate no flow due to plugging by rust particles from the carbon steel piping components, indicating that the test frequency may not provide reasonable assurance that these spray nozzles will remain operational to perform their intended function between testing periods. In light of this, the applicant was asked to provide the technical justification for performing the periodic containment spray nozzle flow testing every fifth refueling outage.

In its response, the applicant stated that during the last regularly scheduled containment spray nozzle air test performed during outage 18R in 2000, two suppression chamber nozzles indicated some degree of flow blockage. No drywell spray nozzles were found to be blocked. The cause was suspected to be deposition of corrosion particles from carbon steel piping upstream of the nozzles. That corrosion was suspected to be a result of the cyclic wetting and drying of the piping that had occurred when the system was tested monthly using torus water in the past.

The applicant also stated that in order to schedule a subsequent repair, an analysis was performed regarding the operability of the suppression chamber spray system with the blocked nozzles. The analysis determined that the SAR containment accident analyses are unaffected by suppression chamber nozzle blockage. The analysis assumed that all ten suppression chamber nozzles were blocked, and demonstrated that the plant design basis accidents could be successfully mitigated. GE provided concurrence to the conclusion that the containment accident analysis is not significantly impacted by blockage of the suppression chamber nozzles (Letter, N. Trikouros [GE] to D. Robare [GE], Impact of Operation of Oyster Creek with Partial Clogging of Torus Spray Nozzles, NSA00416, DRF T23-00787-00, November 8, 2000). Based on these analyses, repair of the two blocked nozzles was scheduled for the next refueling outage, 19R, in 2002.

The applicant further stated that in 2002, during refueling outage 19R, the suppression chamber spray header was flushed with water, such as would occur during an actuation of the suppression chamber spray. Subsequent to this, the nozzle air flow test was re-performed, and all nozzles showed clear, meaning that the water spray had dislodged the particles that caused the previous indication of nozzle plugging during the 2000 air test.

The applicant further stated that testing interval of once every fifth refueling outage for performing the nozzle air test is justified based on the following:

1. Monthly water testing of the piping is no longer performed, removing the source of regular wetting and drying of the carbon steel piping upstream of the nozzles which facilitated corrosion of the piping.

2. Flushing of the system with water, as would occur during an actuation of the suppression chamber spray, discharged and cleared the nozzles that did show as plugged during the air test in 2000.

3. The analyses performed to determine operability of the system with two plugged nozzles showed that SAR containment accident analyses are unaffected by suppression chamber nozzle blockage, even when all ten suppression chamber nozzles were assumed to be blocked, and demonstrated that the plant design basis accidents could be successfully mitigated.

The project team reviewed the applicant's response and determined that the test interval for performing the containment spray nozzle flow testing of once every fifth refueling outage is acceptable since actions have been taken to mitigate the possibility of corrosion products from upstream steel piping blocking the spray nozzles.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.2.2.2.8.1 for further evaluation.

3.2.2.2.8.2 Loss of Material due to General, Pitting and Crevice Corrosion [Item 2]

The project team noted that the applicant did not credit the GALL Report AMR for steel containment isolation components exposed to treated water, which is associated with this further evaluation, for the Oyster Creek engineered safety features systems. This was a new AMR that was not in the draft January 2005 GALL Report.

The project team reviewed Tables 3.2.2.1.1, 3.2.2.1.2, and 3.2.2.1.3 in the OCGS LRA for the ESF systems and noted that other GALL AMR line items that address same material/ environment combinations were appropriately credited. Therefore, the project team determined that this further evaluation is not applicable to Oyster Creek.

3.2.2.2.8.3 Loss of Material due to General, Pitting and Crevice Corrosion [Item 3]

The project team noted that the applicant did not credit the GALL Report AMR for steel piping, piping components, and piping elements exposed to lubricating oil, which is associated with this further evaluation, for the Oyster Creek engineered safety features systems. This was a new AMR that was not in the draft January 2005 GALL Report.

The applicant was asked to clarify which AMPs are credited for loss of material due to general, pitting and crevice corrosion for steel piping, piping components, and piping elements exposed to lubricating oil in the engineered safety features systems. In its response, the applicant stated that September 2005 Revision 1 SRP Section 3.2.2.2.8.3 addressed line item EP-46. This is a new line item that was not in the January 2005 draft SRP. This MEA combination is not present in ESF systems at Oyster Creek. The Oyster Creek LRA used line items AP-30 (3.3.1-16) and SP-25 (3.4.1-3) for carbon steel piping, piping components, and piping elements exposed to lubricating oil in other systems.

The project team reviewed Tables 3.2.2.1.1, 3.2.2.1.2, and 3.2.2.1.3 in the OCGS LRA for the ESF systems and confirmed that no steel components exposed to lubricating oil were identified. Therefore, the project team found the applicant’s response acceptable, and concluded that this further evaluation is not applicable to Oyster Creek.

3.2.2.2.9 Loss of Material Due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion

The applicant addressed loss of material due to general corrosion for steel piping buried in soil in Section 3.2.2.8.3 of the OCGS LRA, in accordance with the draft January 2005 SRP-LR. Therefore, the project team reviewed OCGS LRA Section 3.2.2.2.8.3 against the criteria in SRP-LR Section 3.2.2.2.9.

SRP-LR Section 3.2.2.2.9 stated that loss of material due to general, pitting, crevice, and MIC could occur for steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil. The buried piping and tanks inspection program relies on industry practice, frequency of pipe excavation, and operating experience to manage the effects of loss of material from general, pitting, and crevice corrosion and MIC. The effectiveness of the buried piping and tanks inspection program should be verified to evaluate an applicant's inspection frequency and operating experience with buried components, ensuring that loss of material is not occurring.

In the OCGS LRA Section 3.2.2.2.8.3, the applicant stated that Oyster Creek will implement a Buried Piping Inspection Program, B.1.26, to manage the loss of material in steel piping, piping components, and piping elements exposed to soil in the containment spray system. The Buried Piping Inspection Program includes preventive measures to mitigate corrosion and periodic inspection to manage the effects of corrosion on the pressure-retaining capacity of buried steel piping, piping components, and piping elements. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process. Oyster Creek engineered safety features systems have no buried steel tanks in the scope of license renewal.

The applicant was asked to clarify which AMPs are credited for loss of material due to general, pitting, crevice, and MIC in steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil. In its response, the applicant stated that September 2005

Revision 1 SRP Section 3.2.2.2.9 addressed line item E-42 for loss of material in steel piping in a soil environment due to general, pitting, and crevice corrosion. MIC was added to the aging mechanisms in the September 2005 Revision 1 SRP. This item is addressed in the Oyster Creek LRA in the ESF section (E-42, Table 3.2.1-12, LRA Section 3.2.2.2.8.3). The Buried Piping Inspection Program B.1.26 addresses aging effects from the MIC aging mechanism as referenced in the reconciliation document, Attachment 5, Item No. 17. The September 2005 Revision 1 GALL now specifies verification that at least one focused or opportunistic inspection in historically or suspected susceptible areas be performed prior to the period of extended operation but within the past 10 years. This is addressed in the Oyster Creek LRA description of the Buried Piping Inspection Program B.1.26 as referenced in the reconciliation document, Attachment 1, OC Program No. B.1.26.

The project team reviewed the applicant's response and determined that the applicant's aging management review is consistent with the recommendations in the GALL Report.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.2.2.2.9 for further evaluation.

3.2.2.2.10 Quality Assurance for Aging Management of Non-Safety-Related Components

OCGS LRA Section 3.2.2.2.10 is reviewed by NRR/DE staff and will be addressed separately in Section 3 of the SER related to the OCGS LRA.

Conclusion

On the basis of its review, for component groups evaluated in the GALL Report for which the GALL Report recommends further evaluation, the project team determined that the applicant adequately addressed the issues that were further evaluated. The project team found that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.3 *AMR Results That Are Not Consistent With The GALL Report Or Not Addressed In The GALL Report*

Summary of Information in the Application

In OCGS LRA Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features, the applicant provided information regarding components or material/ environment combination in the GALL Report that it evaluated and identified as not applicable to its plant.

In OCGS LRA Tables 3.2.2.1.1 through 3.2.2.1.3, the applicant provided additional details of the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that are not consistent with the GALL Report. Specifically, the applicant indicated, via Notes F through J, that neither the identified component nor the material/ environment combination is evaluated in the GALL Report and provided information concerning how the aging effect requiring management will be managed.

Project Team Evaluation

The project team reviewed additional details of the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that the applicant identified as not applicable to its plant.

The project team did not review the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that are not consistent with the GALL Report or are not addressed in the GALL Report. These AMR line items were reviewed by NRR/DE staff, and are discussed in the SER related to the OCGS LRA.

3.2.2.3.1 Aging Effect/mechanism in Table 3.2.1 That Are Not Applicable for OCGS

The project team reviewed OCGS LRA Table 3.2.1, which provides a summary of aging management evaluations for the engineered safety features evaluated in the GALL Report.

In OCGS LRA Table 3.2.1, Item 3.2.1-14, the applicant stated that loss of fracture toughness due to thermal aging embrittlement for cast austenitic stainless steel piping, piping components, and piping elements exposed to treated water >250ºC (>482ºF) is not applicable at OCGS. Oyster Creek has no CASS components susceptible to thermal aging embrittlement located in the portions of the ESF Systems governed by Group B Quality Standards. CASS components located in the portions of the ESF Systems governed by Group A Quality Standards are discussed in Item Number 3.1.1-43 and Item Number 3.1.1- 47.

The project team reviewed the ESF AMR line items in the OCGS LRA and confirmed that Oyster Creek has no CASS components susceptible to thermal aging embrittlement located in the portions of the ESF Systems . Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.2.1, Item 3.2.1-15, the applicant stated that cracking due to SCC and IGSCC for stainless steel piping, piping components, and piping elements exposed to treated water >60ºC (>140ºF) is not applicable at OCGS. Oyster Creek has no stainless steel piping, piping components, or piping elements susceptible to stress corrosion cracking or intergranular stress corrosion cracking located in the portions of the ESF Systems governed by Group B Quality Standards. These items located in the portions of the ESF Systems governed by Group A Quality Standards are discussed in Item Number 3.1.1-9.

The project team reviewed the ESF AMR line items in the OCGS LRA and determined that Oyster Creek has no stainless steel piping, piping components, or piping elements susceptible to stress corrosion cracking or intergranular stress corrosion cracking located in the portions of the ESF Systems governed by Group B Quality Standards. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.2.1, Item 3.2.1-16, the applicant stated that wall thinning due to flow accelerated corrosion for steel piping, piping components, and piping elements exposed to air and steam or treated water is not applicable at OCGS. Oyster Creek has no steel piping, piping components, or piping elements susceptible to flow accelerated corrosion in the portions of the ESF systems governed by Group B Quality Standards, as these portions of the ESF systems are low-temperature systems.

The project team reviewed the ESF AMR line items in the OCGS LRA and determined that Oyster Creek has no steel piping, piping components, or piping elements susceptible to flow accelerated corrosion located in the portions of the ESF Systems governed by Group B Quality Standards. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.2.1, Item 3.2.1-17, the applicant stated that loss of material due to pitting, crevice, and galvanic corrosion for copper alloy piping, piping components, and piping elements, and heat exchanger tubes exposed to closed-cycle cooling water is not applicable at OCGS. Oyster Creek has no copper alloy piping, piping components, or piping elements exposed to closed-cycle cooling water in the ESF systems.

The project team reviewed the ESF AMR line items in the OCGS LRA and determined that Oyster Creek has no copper alloy piping, piping components, or piping elements exposed to closed-cycle cooling water in the ESF systems. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.2.1, Item 3.2.1-18, the applicant stated that loss of material due to selective leaching for copper alloy >15% Zn piping, piping components, and piping elements, and heat exchanger tubes exposed to closed-cycle cooling water is not applicable at OCGS. Oyster Creek has no copper alloy piping, piping components, or piping elements containing >15% Zn exposed to closed-cycle cooling water in the ESF systems.

The project team reviewed the ESF AMR line items in the OCGS LRA and determined that Oyster Creek has no copper alloy piping, piping components, or piping elements containing >15% Zn exposed to closed-cycle cooling water in the ESF systems. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.2.1, Item 3.2.1-20, the applicant stated that cracking due to cyclic loading, stress corrosion cracking for high-strength steel closure bolting exposed to air with steam or water leakage is not applicable at OCGS. Oyster Creek has no high-strength steel closure bolting in the ESF systems.

The project team reviewed the ESF AMR line items in the OCGS LRA and determined that Oyster Creek has no high strength steel closure bolting in the ESF systems. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.2.1, Item 3.2.1-21, the applicant stated that loss of material due to pitting and crevice corrosion for stainless steel piping, piping components, and piping elements, and heat exchanger shell side components (including tubes) serviced by closed-cycle cooling system is not applicable at OCGS. Oyster Creek has no stainless steel piping, piping components, or piping elements, or heat exchanger shell side components, including tubes, exposed to a closed-cycle cooling water environment in the ESF systems.

The project team reviewed the ESF AMR line items in the OCGS LRA and determined that Oyster Creek has no stainless steel piping, piping components, or piping elements or heat exchanger shell side components, including tubes exposed to closed-cycle cooling water in the ESF systems. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.2.1, Item 3.2.1-22, the applicant stated that reduction of heat transfer due to fouling for stainless steel heat exchanger tubes exposed to closed-cycle cooling water is not applicable at OCGS. Oyster Creek has no stainless steel heat exchanger tubes exposed to a closed-cycle cooling water environment in the ESF systems.

The project team reviewed the ESF AMR line items in the OCGS LRA and determined that Oyster Creek has no stainless steel heat exchanger tubes exposed to closed-cycle cooling water in the ESF systems. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.2.1, Item 3.2.1-23, the applicant stated that loss of material due to pitting, crevice, and MIC and fouling for stainless steel heat exchanger shell side components (including tubes) exposed to raw water is not applicable at OCGS. Oyster Creek has no stainless steel heat exchanger shell side components, including tubes, exposed to a raw water environment in the ESF systems.

The project team reviewed the ESF AMR line items in the OCGS LRA and determined that Oyster Creek has no stainless steel heat exchanger shell side components, including tubes exposed to raw water in the ESF systems. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.2.1, Item 3.2.1-26, the applicant stated that loss of material due to general, pitting, and crevice corrosion for steel heat exchanger shell side components exposed to closed-cycle cooling water is not applicable at OCGS. Oyster Creek has no steel heat exchanger shell side components exposed to closed-cycle cooling water in the ESF systems.

The project team reviewed the ESF AMR line items in the OCGS LRA and determined that Oyster Creek has no steel heat exchanger shell side components exposed to closed-cycle cooling water in the ESF systems. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.2.1, Item 3.2.1-27, the applicant stated that loss of material due to general, pitting, crevice, and MIC, and fouling for steel heat exchanger shell side components (including tubes) exposed to raw water is not applicable at OCGS. Oyster Creek has no steel heat exchanger shell side components, including tubes, exposed to raw water in the ESF systems.

The project team reviewed the ESF AMR line items in the OCGS LRA and determined that Oyster Creek has no steel heat exchanger shell side components exposed to closed-cycle cooling water in the ESF systems. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.2.1, Item 3.2.1-28, the applicant stated that reduction of heat transfer due to fouling for steel and stainless steel heat exchanger tubes (serviced by open-cycle cooling water) exposed to raw water is not applicable at OCGS. Oyster Creek has no steel or stainless steel heat exchanger tubes exposed to open-cycle cooling water or raw water in the ESF systems.

The project team reviewed the ESF AMR line items in the OCGS LRA and determined that Oyster Creek has no steel or stainless steel heat exchanger tubes exposed to raw water in the ESF systems. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.2.1, Item 3.2.1-36, the applicant stated that the AMR stating no aging effect for steel piping, piping components, and piping elements exposed to air-indoor uncontrolled (external), or concrete is not applicable at OCGS. Oyster Creek has no steel piping, piping components, or piping elements exposed to air-indoor uncontrolled in the ESF systems.

The project team reviewed the ESF AMR line items in the OCGS LRA and determined that Oyster Creek has no steel piping, piping components, or piping elements exposed to air-indoor uncontrolled in the ESF systems. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.2.1, Item 3.2.1-37, the applicant stated that the AMR stating no aging effect for steel and copper alloy piping, piping components, and piping elements exposed to lubricating oil (no water pooling) is not applicable at OCGS. Oyster Creek has no steel or copper alloy piping, piping components, or piping elements exposed to lubricating oil (no water pooling) in the ESF systems.

The project team reviewed the ESF AMR line items in the OCGS LRA and determined that Oyster Creek has no steel or copper alloy piping, piping components, or piping elements exposed to lubricating oil (no water pooling) in the ESF systems. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.2.1, Item 3.2.1-38, the applicant stated that the AMR stating no aging effect for steel, stainless steel and copper alloy piping, piping components, and piping elements exposed to gas is not applicable at OCGS. Oyster Creek has no steel, stainless steel or copper alloy piping, piping components, or piping elements exposed to gas in the ESF systems.

The project team reviewed the ESF AMR line items in the OCGS LRA and determined that Oyster Creek has no steel, stainless steel or copper alloy piping, piping components, or piping elements exposed to gas in the ESF systems. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

3.2.2.3.2 Engineered Safety Features AMR Line Items That Have No Aging Effect (OCGS LRA Tables 3.2.2.1.1 Through 3.2.2.1.3)

In OCGS LRA Tables 3.2.2.1.1 through 3.2.2.1.3, the applicant identified line-items where no aging effects were identified as a result of its aging review process.

In OCGS LRA Tables 3.2.2.1.1 through 3.2.2.1.3, the applicant identified AMR line-items where no aging effects were identified as a result of its aging review process. Specifically, instances in which the applicant stated that no aging effects were identified occurred when components fabricated from aluminum were exposed to an air-indoor uncontrolled environment.

The project team reviewed the recommendations in the GALL Report for this material/environment combination, and determined that the applicant's evaluations are consistent with the recommendations in the GALL Report. In addition, the project team reviewed the applicant's AMR technical basis documents listed in Attachment 5 of this audit and review report for the engineered safety features systems, and determined that no significant aging effects were identified for ESF system components with this material/environment combination.

On the basis of its review of current industry research and operating experience, the project team found that aluminum exposed to an air-indoor uncontrolled environment will not result in aging that will be of concern during the period of extended operation. Therefore, the project team determined that there are no applicable aging effects requiring management for this material/environment combination.

In OCGS LRA Tables 3.2.2.1.1 through 3.2.2.1.3, the applicant identified AMR line-items where no aging effects were identified as a result of its aging review process. Specifically, instances in which the applicant stated that no aging effects were identified occurred when components fabricated from glass were exposed to an air-indoor uncontrolled environment.

The project team reviewed the recommendations in the GALL Report for this material/environment combination, and determined that the applicant's evaluations are consistent with the recommendations in the GALL Report. In addition, the project team reviewed the applicant's AMR technical basis documents listed in Attachment 5 of this audit and review report for the engineered safety features systems, and determined that no significant aging effects were identified for ESF system components with this material/environment combination.

On the basis of its review of current industry research and operating experience, the project team found that glass exposed to an air-indoor uncontrolled environment will not result in aging that will be of concern during the period of extended operation. Therefore, the project team determined that there are no applicable aging effects requiring management for this material/environment combination.

In OCGS LRA Tables 3.2.2.1.1 through 3.2.2.1.3, the applicant identified AMR line-items where no aging effects were identified as a result of its aging review process. Specifically, instances in which the applicant stated that no aging effects were identified occurred when components fabricated from stainless steel were exposed to a concrete or lubricating oil environment.

The project team reviewed the recommendations in the GALL Report for this material/environment combination, and determined that the applicant's evaluations are consistent with the recommendations in the GALL Report. In addition, the project team reviewed the applicant's AMR technical basis documents listed in Attachment 5 of this audit and review report for the engineered safety features systems, and determined that no significant aging effects were identified for ESF system components with this material/environment combination.

On the basis of its review of current industry research and operating experience, the project team found that stainless steel exposed to a concrete or lubricating oil environment will not result in aging that will be of concern during the period of extended operation. Therefore, the project team determined that there are no applicable aging effects requiring management for this material/environment combination.

In OCGS LRA Tables 3.2.2.1.1 through 3.2.2.1.3, the applicant identified AMR line-items where no aging effects were identified as a result of its aging review process. Specifically, instances in which the applicant stated that no aging effects were identified occurred when components fabricated from stainless steel, cast austenitic stainless steel, galvanized steel, copper alloy, and nickel alloy were exposed to an air-indoor uncontrolled environment.

The project team reviewed the recommendations in the GALL Report for this material/environment combination, and determined that the applicant's evaluations are consistent with the recommendations in the GALL Report. In addition, the project team reviewed the applicant's AMR technical basis documents listed in Attachment 5 of this audit and review report for the engineered safety features systems, and determined that no significant aging effects were identified for ESF system components with this material/environment combination.

On the basis of its review of current industry research and operating experience, the project team found that stainless steel, cast austenitic stainless steel, galvanized steel, copper alloy, and nickel alloy exposed to an air-indoor uncontrolled environment will not result in aging that will be of concern during the period of extended operation. Therefore, the project team determined that there are no applicable aging effects requiring management for this material/environment combination.

Conclusion

On the basis of its review, the project team found that the applicant appropriately identified AMR results involving material, environment, aging effects requiring management, and AMP combinations that are not applicable to OCGS, and AMR results involving material and environment combinations that do not have aging effects requiring management at OCGS.

3.2.3 Conclusion

On the basis of its review, the project team determined that the applicant has demonstrated that the aging effects associated with the engineered safety features components will be adequately managed. The project team also reviewed the applicable UFSAR supplement program summaries and concluded that they adequately describe the AMPs credited for managing aging of the engineered safety features components, as required by 10 CFR 54.21(d).

3.3 OCGS LRA Section 3.3 – Aging Management of Auxiliary Systems

This section of the audit and review report documents the project team's review and evaluation of the OCGS aging management review (AMR) results for the aging management of the components and component groups associated with the following auxiliary systems: (1) ?C" battery room heating & ventilation, (2) 4160 V switchgear room ventilation, (3) 480 V switchgear room ventilation, (4) battery and MG set room ventilation, (5) chlorination system, (6) circulating water system, (7) containment inerting system, (8) containment vacuum breakers, (9) control rod drive system, (10) control room HVAC, (11) drywell floor and equipment drains, (12) emergency diesel generator and auxiliary system, (13) emergency service water system, (14) fire protection system, (15) fuel storage and handling, (16) equipment, (17) hardened vent system, (18) heating & process steam system, (19) hydrogen & oxygen monitoring system, (20) instrument (control) air system, (21) main fuel oil storage & transfer system, (22) miscellaneous floor and equipment drain system, (23) nitrogen supply system, (24) noble metals monitoring system, (25) post-accident sampling system, (26) process sampling system, (27) radiation monitoring system, (28) radwaste area heating and ventilation system, (29) reactor building closed cooling water system, (30) reactor building floor and equipment drains, (31) reactor building ventilation system, (32) reactor water cleanup system, (33) roof drains and overboard discharge, (34) sanitary waste system, (35) service water system, (36) shutdown cooling system, (37) spent fuel pool cooling system, (38) standby liquid control system (liquid poison system), (39) traveling in-core probe system, (40) turbine building closed cooling water system, and (41) water treatment & distribution system.

3.3.1 Summary of Technical Information in the Application

In the OCGS LRA, Section 3.3, the applicant provided the results of its AMRs for the auxiliary system components and component groups.

In OCGS LRA Table 3.3.1, ?Summary of Aging Management Evaluations for the Auxiliary Systems," the applicant provided a summary comparison of its AMR line-items with the AMR line-items evaluated in the GALL Report for the auxiliary system components and component groups. The applicant also identified, for each component type in the OCGS LRA Table 3.3.1, those AMRs that are consistent with the GALL Report, those for which the GALL Report recommends further evaluation, and those AMRs that are not addressed in the OCGS LRA, together with the basis for their exclusion.

In the OCGS LRA Tables 3.3.2.1.1 through 3.3.2.1.41, the applicant provided the AMR results for component types associated with (1) ?C" battery room heating & ventilation, (2) 4160 V switchgear room ventilation, (3) 480 V switchgear room ventilation, (4) battery and MG set room ventilation, (5) chlorination system, (6) circulating water system, (7) containment inerting system, (8) containment vacuum breakers, (9) control rod drive system, (10) control room HVAC, (11) drywell floor and equipment drains, (12) emergency diesel generator and auxiliary system, (13) emergency service water system, (14) fire protection system, (15) fuel storage and handling, (16) equipment, (17) hardened vent system, (18) heating & process steam system, (19) hydrogen & oxygen monitoring system, (20) instrument (control) air system, (21) main fuel oil storage & transfer system, (22) miscellaneous floor and equipment drain system, (23) nitrogen supply system, (24) noble metals monitoring system, (25) post-accident sampling system, (26) process sampling system, (27) radiation monitoring system, (28) radwaste area heating and ventilation system, (29) reactor building closed cooling water system, (30) reactor building floor and equipment drains, (31) reactor building ventilation system, (32) reactor water cleanup system, (33) roof drains and overboard discharge, (34) sanitary waste system, (35) service water system, (36) shutdown cooling system, (37) spent fuel pool cooling system, (38) standby liquid control system (liquid poison system), (39) traveling in-core probe system, (40) turbine building closed cooling water system, and (41) water treatment & distribution system. Specifically, the information for each component type included the intended function, material, environment, aging effect requiring management, AMPs, the GALL Report Volume 2 item, cross reference to the OCGS LRA Table 3.3.1 (Table 1), and generic and plant-specific notes related to consistency with the GALL Report.

The applicant's AMRs incorporated applicable operating experience in the determination of the aging effects requiring management (AERMs). These reviews included the evaluation of both plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.3.2 Project Team Evaluation

The project team reviewed OCGS LRA Section 3.3 to determine if the applicant provided sufficient information to demonstrate that the effects of aging for the auxiliary system components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The project team reviewed certain identified AMR line-items to confirm the applicant's claim that these AMR line-items were consistent with the GALL Report. The project team did not repeat its review of the matters described in the GALL Report. However, the project team did verify that the material presented in the OCGS LRA was applicable and that the applicant had identified the appropriate GALL Report AMR line-items. The project team's audit evaluation is documented in Section 3.3.2.1 of this audit and review report. In addition, the project team's evaluations of the AMPs are documented in Section 3.0.3 of this audit and review report.

The project team reviewed those selected AMR line-items for which further evaluation is recommended by the GALL Report. The project team confirmed that the applicant's further evaluations were in accordance with the acceptance criteria in the SRP-LR. The project team's audit evaluation is documented in Section 3.3.2.2 of this audit and review report.

The project team did not review the remaining AMR line-items that were not consistent with or not addressed in the GALL Report. These were reviewed by the NRC DE staff and documented in the SER for the Oyster Creek plant.

Finally, the project team reviewed the AMP summary descriptions in the UFSAR Supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the auxiliary systems.

Table 3.3-1 below provides a summary of the project team's evaluation of the components, aging effects/aging mechanisms, and AMPs listed in LRA Section 3.3 that are addressed in the GALL Report. It also includes the section of the audit and review report in which the project team's evaluation is documented. It should be noted that the line items in this table correspond to the line items in Table 3.3-1 of the September 2005 Revision 1 SRP-LR document; therefore, in many cases, they do not match the line items in Table 3.3.1 of the OCGS LRA. The SRP-LR line item number is denoted parenthetically in the column 1 entry. Also, line items that are applicable only to PWR plants are not included in this table; therefore, certain SRP-LR line item numbers do not appear in this table.

Table 3.3-1 Staff Evaluation for Auxiliary System Components in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Steel cranes – structural girders exposed to air – indoor uncontrolled (external) (Item 3.3.1-1)	Cumulative fatigue damage	TLAA to be evaluated for structural girders of cranes. See the	TLAA	TLAAs were reviewed by NRR/DE staff. (See Audit Report Section 3.3.2.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
		Standard Review Plan, Section 4.7 for generic guidance for meeting the requirements of 10 CFR 54.21(c)(1)		
Steel and stainless steel piping, piping components, piping elements, and heat exchanger components exposed to air – indoor uncontrolled, treated borated water or treated water (Item 3.3.1-2)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	TLAAs were reviewed by NRR/DE staff. (See Audit Report Section 3.3.2.2.1)
Stainless steel heat exchanger tubes exposed to treated water (Item 3.3.1-3)	Reduction of heat transfer due to fouling	Water Chemistry and One-Time Inspection	Water Chemistry (B.1.2)	Acceptable, since one-time inspection is credited for other aging effects in the same systems. (See Audit Report Section 3.3.2.2.2)
Stainless steel piping, piping components, and piping elements exposed to sodium pentaborate solution > 60°C (> 140°F) (Item 3.3.1-4)	Cracking due to stress corrosion cracking	Water Chemistry and One-Time Inspection	Water Chemistry (B.1.2) and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. (See Audit Report Section 3.3.2.2.3.1)
Stainless steel and stainless clad steel heat exchanger components exposed to treated water > 60°C (> 140°F) (Item 3.3.1-5)	Cracking due to stress corrosion cracking	A plant-specific AMP is to be evaluated.	One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. (See Audit Report Section 3.3.2.2.3.2)
Stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust (Item 3.3.1-6)	Cracking due to stress corrosion cracking	A plant-specific AMP is to be evaluated.	Not Applicable	Not applicable since the diesel engine exhaust piping is carbon steel. (See Audit Report Section 3.3.2.2.3.3)
High-strength steel closure bolting exposed to air with	Cracking due to stress corrosion cracking, cyclic	Bolting Integrity AMP to be augmented by	Bolting Integrity (B.1.12)	Consistent with GALL, which recommends further evaluation. (See

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
steam or water leakage. (Item 3.3.1-10)	loading	appropriate inspection to detect cracking if the bolts are not otherwise replaced during maintenance.		Audit Report Section 3.3.2.2.4.4)
Elastomer seals and components exposed to air – indoor uncontrolled (internal/external) (Item 3.3.1-11)	Hardening and loss of strength due to elastomer degradation	A plant-specific AMP is to be evaluated	Periodic Inspection of Ventilation Systems (B.2.4)	Reviewed by NRR/DE Staff. (See Audit Report Section 3.3.2.2.5.1)
Elastomer lining exposed to treated water or treated borated water (Item 3.3.1-12)	Hardening and loss of strength due to elastomer degradation	A plant-specific AMP is to be evaluated.	Periodic Inspection (B.2.5)	Reviewed by NRR/DE Staff. (See Audit Report Section 3.3.2.2.5.2)
Boral, boron steel spent fuel storage racks neutron-absorbing sheets exposed to treated water or treated borated water (Item 3.3.1-13)	Reduction of neutron-absorbing capacity and loss of material due to general corrosion	A plant-specific AMP is to be evaluated	None	Acceptable since operating experience shows that aging effects for this component are insignificant. (See Audit Report Section 3.3.2.2.6)
Steel piping, piping component, and piping elements exposed to lubricating oil (Item 3.3.1-14)	Loss of material due to general, pitting, and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Lubricating Oil Monitoring Activities (B.2.2) and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation AMP B.2.2 was reviewed by NRR/DE staff. (See Audit Report Section 3.3.2.2.7.1)
Steel reactor coolant pump oil collection system piping, tubing, and valve bodies exposed to lubricating oil (Item 3.3.1-15)	Loss of material due to general, pitting, and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Not Applicable	Not applicable since Oyster Creek does not have a reactor coolant pump oil collection system. (See Audit Report Section 3.3.2.2.7.1)
Steel reactor coolant pump oil collection system tank exposed to lubricating oil (Item 3.3.1-16)	Loss of material due to general, pitting, and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection to evaluate the thickness of the lower portion of the tank	Not Applicable	Not applicable since Oyster Creek does not have a reactor coolant pump oil collection system. (See Audit Report Section 3.3.2.2.7.1)
Steel piping, piping components, and	Loss of material due to general,	Water Chemistry and	Water Chemistry (B.1.2) and	Consistent with GALL, which recommends

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
piping elements exposed to treated water (Item 3.3.1-17)	pitting, and crevice corrosion	One-Time Inspection	One-Time Inspection (B.1.24)	further evaluation (See Audit Report Section 3.3.2.2.7.2)
Stainless steel and steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust (Item 3.3.1-18)	Loss of material/general (steel only), pitting and crevice corrosion	A plant-specific AMP is to be evaluated	Periodic Inspection (B.2.5)	Reviewed by NRR/DE Staff. (See Audit Report Section 3.3.2.2.7.3)
Steel (with or without coating or wrapping) piping, piping components, and piping elements exposed to soil (Item 3.3.1-19)	Loss of material due to general, pitting, crevice, and MIC	Buried Piping and Tanks Surveillance or Buried Piping and Tanks Inspection	Buried Piping Inspection (B.1.26)	Consistent with GALL, which recommends further evaluation. (See Audit Report Section 3.3.2.2.8)
Steel piping, piping components, piping elements, and tanks exposed to fuel oil (Item 3.3.1-20)	Loss of material due to general, pitting, crevice, and MIC, and fouling	Fuel Oil Chemistry and One-Time Inspection	Fuel Oil Chemistry (B.1.22) and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. (See Audit Report Section 3.3.2.2.9.1)
Steel heat exchanger components exposed to lubricating oil (Item 3.3.1-21)	Loss of material due to general, pitting, crevice, and MIC, and fouling	Lubricating Oil Analysis and One-Time Inspection	Lubricating Oil Monitoring Activities (B.2.2) and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. AMP B.2.2 was reviewed by NRR/DE staff. (See Audit Report Section 3.3.2.2.9.2)
Steel with elastomer lining or stainless steel cladding piping, piping components, and piping elements exposed to treated water and treated borated water (Item 3.3.1-22)	Loss of material due to pitting and crevice corrosion (only for steel after lining/cladding degradation)	Water Chemistry and One-Time Inspection	Water Chemistry (B.1.2) and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. (See Audit Report Section 3.3.2.2.10.1)
Stainless steel and steel with stainless steel cladding heat exchanger components exposed to treated water (Item 3.3.1-23)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Water Chemistry (B.1.2) and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. (See Audit Report Section 3.3.2.2.10.2)
Stainless steel and aluminum piping, piping components,	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time	Water Chemistry (B.1.2) and One-Time	Consistent with GALL, which recommends further evaluation. (See

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
and piping elements exposed to treated water (Item 3.3.1-24)		Inspection	Inspection (B.1.24)	Audit Report Section 3.3.2.2.10.2)
Copper alloy HVAC piping, piping components, piping elements exposed to condensation (external) (Item 3.3.1-25)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Periodic Inspection of Ventilation Systems (B.2.4)	Reviewed by NRR/DE Staff. (See Audit Report Section 3.3.2.2.10.3)
Copper alloy piping, piping components, and piping elements exposed to lubricating oil (Item 3.3.1-26)	Loss of material due to pitting and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Lubricating Oil Monitoring Activities (B.2.2) and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. AMP B.2.2 was reviewed by NRR/DE staff. (See Audit Report Section 3.3.2.2.10.4)
Stainless steel HVAC ducting and aluminum HVAC piping, piping components and piping elements exposed to condensation (Item 3.3.1-27)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	One-time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. (See Audit Report Section 3.3.2.2.10.5)
Copper alloy fire protection piping, piping components, and piping elements exposed to condensation (internal) (Item 3.3.1-28)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Not Applicable	Not applicable since no GALL AMR line items related to this component group/ aging effect combination were credited in the OCGS LRA. (See Audit Report Section 3.3.2.2.10.6)
Stainless steel piping, piping components, and piping elements exposed to soil (Item 3.3.1-29)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Not Applicable	Not applicable since no GALL AMR line items related to this component group/ aging effect combination were credited in the OCGS LRA. (See Audit Report Section 3.3.2.2.10.7)
Stainless steel piping, piping components, and piping elements exposed to sodium pentaborate solution	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Water Chemistry (B.1.2) and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. (See Audit Report Section 3.3.2.2.10.8)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
(Item 3.3.1-30)				
Copper alloy piping, piping components, and piping elements exposed to treated water (Item 3.3.1-31)	Loss of material due to pitting, crevice, and galvanic corrosion	Water Chemistry and One-Time Inspection	Water Chemistry (B.1.2) and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. (See Audit Report Section 3.3.2.2.11)
Stainless steel, aluminum and copper alloy piping, piping components, and piping elements exposed to fuel oil (Item 3.3.1-32)	Loss of material due to pitting, crevice, and MIC	Fuel Oil Chemistry and One-Time Inspection	Fuel Oil Chemistry (B.1.22) and One-Time Inspection (B.1.24) (aluminum and copper alloy) or Fuel Oil Chemistry (B.1.22) (stainless steel)	Consistent with GALL (aluminum and copper alloy), which recommends further evaluation. Acceptable (stainless steel) since one-time inspection is performed for other materials in the same environment that are leading indicators of corrosion. (See Audit Report Section 3.3.2.2.12.1)
Stainless steel piping, piping components, and piping elements exposed to lubricating oil (Item 3.3.1-33)	Loss of material due to pitting, crevice, and MIC	Lubricating Oil Analysis and One-Time Inspection	Lubricating Oil Monitoring Activities (B.2.2) and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. AMP B.2.2 was reviewed by NRR/DE staff. (See Audit Report Section 3.3.2.2.12.2)
Elastomer seals and components exposed to air – indoor uncontrolled (internal or external) (Item 3.3.1-34)	Loss of material due to Wear	A plant-specific AMP is to be evaluated.	Periodic Inspection of Ventilation Systems (B.2.4)	Reviewed by NRR/DE Staff. (See Audit Report Section 3.3.2.2.13)
Boraflex spent fuel storage racks neutron-absorbing sheets exposed to treated water (Item 3.3.1-36)	Reduction of neutron-absorbing capacity due to boraflex degradation	Boraflex Monitoring	Boraflex Rack Management (B.1.15)	Consistent with GALL. (See Audit Report Section 3.3.2.1)
Stainless steel piping, piping components, and piping elements exposed to treated water > 60°C (> 140°F) (Item 3.3.1-37)	Cracking due to stress corrosion cracking, intergranular stress corrosion cracking	BWR Reactor Water Cleanup System	BWR Reactor Water Cleanup System (B.1.18)	Consistent with GALL. (See Audit Report Section 3.3.2.1)
Stainless steel piping, piping components, and piping elements exposed to treated	Cracking due to stress corrosion cracking	BWR Stress Corrosion Cracking and Water	Not Applicable	Not applicable since Oyster Creek has no stainless steel non-RCPB shutdown

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
water > 60°C (> 140°F) (Item 3.3.1-38)		Chemistry		cooling system piping exposed to treated water >140F. (See Audit Report Section 3.3.2.3.1)
Stainless steel BWR spent fuel storage racks exposed to treated water > 60°C (> 140°F) (Item 3.3.1-39)	Cracking due to stress corrosion cracking	Water Chemistry	Not Applicable	Not applicable since stainless steel spent fuel storage racks are exposed to treated water <140F. (See Audit Report Section 3.3.2.3.1)
Steel tanks in diesel fuel oil system exposed to air – outdoor (external) (Item 3.3.1-40)	Loss of material due to general, pitting, and crevice corrosion	Aboveground Steel Tanks	Aboveground Outdoor Tanks (B.1.21)	Consistent with GALL. (See Audit Report Section 3.3.2.1)
High-strength steel closure bolting exposed to air with steam or water leakage (Item 3.3.1-41)	Cracking due to cyclic loading, stress corrosion cracking	Bolting Integrity	Not Applicable	Not applicable since auxiliary system high strength steel closure bolting is only applicable to the CRD system, and this is addressed in item 3.3.1-7. (See Audit Report Section 3.3.2.3.1)
Steel closure bolting exposed to air with steam or water leakage (Item 3.3.1-42)	Loss of material due to general corrosion	Bolting Integrity	Not Applicable	Not applicable since no auxiliary system steel closure bolting is exposed to air with steam or water leakage, except the CRD system, which is addressed in item 3.3.1-7. (See Audit Report Section 3.3.2.3.1)
Steel bolting and closure bolting exposed to air – indoor uncontrolled (external) or air – outdoor (External) (Item 3.3.1-43)	Loss of material due to general, pitting, and crevice corrosion	Bolting Integrity	Bolting Integrity, or ASME Section XI, Subsection IWE, or Inspection of Overhead Heavy Load and Light Load Handling System, or Structures Monitoring	Acceptable since the ASME Section XI, Subsection IWE, inspection of overhead heavy load and light load handling system, and structures monitoring programs are consistent with the Bolting Integrity Program for this component group/ aging effect

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
				combination. (See Audit Report Section 3.3.2.1.6.1)
Steel compressed air system closure bolting exposed to condensation (Item 3.3.1-44)	Loss of material due to general, pitting, and crevice corrosion	Bolting Integrity	Not Applicable	Not applicable since instrument air system steel closure bolting is not exposed to condensation. (See Audit Report Section 3.3.2.3.1)
Steel closure bolting exposed to air – indoor uncontrolled (external) (Item 3.3.1-45)	Loss of preload due to thermal effects, gasket creep, and self-loosening	Bolting Integrity	Bolting Integrity (B.1.12), or ASME Section XI, Subsection IWE (B.1.27)	Consistent with GALL for AMRs crediting bolting integrity. Acceptable for AMRs crediting ASME Section XI, Subsection IWE, since it is consistent with the Bolting Integrity Program for this component group/ aging effect combination. (See Audit Report Section 3.3.2.1.7)
Stainless steel and stainless clad steel piping, piping components, piping elements, and heat exchanger components exposed to closed cycle cooling water > 60°C (> 140°F) (Item 3.3.1-46)	Cracking due to stress corrosion cracking	Closed-Cycle Cooling Water System	Not Applicable	Not applicable since no GALL AMR line items related to this component group/ aging effect combination were credited in the OCGS LRA.
Steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to closed cycle cooling water (Item 3.3.1-47)	Loss of material due to general, pitting, and crevice corrosion	Closed-Cycle Cooling Water System	Closed-Cycle Cooling Water System (B.1.14) and One-Time Inspection (B.1.24)	Consistent with GALL. Addition of one-time inspection provides additional assurance that aging effects are adequately managed. (See Audit Report Section 3.3.2.1.6.2)
Steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to closed cycle cooling water (Item 3.3.1-48)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	Closed-Cycle Cooling Water System (B.1.14)	Consistent with GALL. (See Audit Report Section 3.3.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Stainless steel; steel with stainless steel cladding heat exchanger components exposed to closed cycle cooling water (Item 3.3.1-49)	Loss of material due to MIC	Closed-Cycle Cooling Water System	Closed-Cycle Cooling Water System (B.1.14)	Consistent with GALL. (See Audit Report Section 3.3.2.1)
Stainless steel piping, piping components, and piping elements exposed to closed cycle cooling water (Item 3.3.1-50)	Loss of material due to pitting and crevice corrosion	Closed-Cycle Cooling Water System	Closed-Cycle Cooling Water System (B.1.14)	Consistent with GALL. (See Audit Report Section 3.3.2.1)
Copper alloy piping, piping components, piping elements, and heat exchanger components exposed to closed cycle cooling water (Item 3.3.1-51)	Loss of material due to pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	Closed-Cycle Cooling Water System (B.1.14)	Consistent with GALL (See Audit Report Section 3.3.2.1)
Steel, stainless steel, and copper alloy heat exchanger tubes exposed to closed cycle cooling water (Item 3.3.1-52)	Reduction of heat transfer due to fouling	Closed-Cycle Cooling Water System	Closed-Cycle Cooling Water System (B.1.14)	Consistent with GALL.. (See Audit Report Section 3.3.2.1)
Steel compressed air system piping, piping components, and piping elements exposed to condensation (internal) (Item 3.3.1-53)	Loss of material due to general and pitting corrosion	Compressed Air Monitoring	Not Applicable	Not applicable since no GALL AMR line items related to this component group/ aging effect combination were credited in the OCGS LRA.
Stainless steel compressed air system piping, piping components, and piping elements exposed to internal condensation (Item 3.3.1-54)	Loss of material due to pitting and crevice corrosion	Compressed Air Monitoring	Not Applicable	Not applicable since no GALL AMR line items related to this component group/ aging effect combination were credited in the OCGS LRA.
Steel ducting closure bolting exposed to air – indoor uncontrolled (external) (Item 3.3.1-55)	Loss of material due to general corrosion	External Surfaces Monitoring	Not Applicable	Not applicable since no GALL AMR line items related to this component group/ aging effect combination were credited in the OCGS LRA.

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Steel HVAC ducting and components external surfaces exposed to air – indoor uncontrolled (external) (Item 3.3.1-56)	Loss of material due to general corrosion	External Surfaces Monitoring	Structures Monitoring (B.1.310) or Periodic Inspection (B.2.5) or Periodic Inspection of Ventilation Systems (B.2.4)	Acceptable since the OCGS structures monitoring program is consistent with the GALL external surfaces monitoring program for this component group/ aging effect combination. The OCGS periodic inspection and periodic inspection of ventilation systems programs are appropriate for this component group/ aging effect combination. These AMPs were reviewed by NRR/DE staff. (See Audit Report Section 3.3.2.1.6.3)
Steel piping and components external surfaces exposed to air – indoor uncontrolled (External) (Item 3.3.1-57)	Loss of material due to general corrosion	External Surfaces Monitoring	Fire Protection (B.1.19) or Fire Water System (B.1.20) or Structures Monitoring (B.1.31) or Periodic Inspection of Ventilation Systems (B.2.4)	Acceptable since the OCGS fire protection, fire water system, and structures monitoring programs are consistent with the GALL external surfaces monitoring program for this component group/ aging effect combination. The OCGS periodic inspection of ventilation systems program is appropriate for this component group/ aging effect combination. This AMP was reviewed by NRR/DE staff. (See Audit Report Section 3.3.2.1.10)
Steel external surfaces exposed to air – indoor uncontrolled (external), air – outdoor (external), and condensation (external) (Item 3.3.1-58)	Loss of material due to general corrosion	External Surfaces Monitoring	Fire Protection (B.1.19), or Fire Water System (B.1.20), or Structures Monitoring (B.1.31), or Periodic	Acceptable since the OCGS fire protection, fire water system, and structures monitoring programs are consistent with the GALL external surfaces monitoring

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
			Inspection of Ventilation Systems (B.2.4)	program for this component group/ aging effect combination. The OCGS periodic inspection of ventilation systems program is appropriate for this component group/ aging effect combination. This AMP was reviewed by NRR/DE staff. (See Audit Report Section 3.3.2.1.10)
Steel heat exchanger components exposed to air – indoor uncontrolled (external) or air -outdoor (external) (Item 3.3.1-59)	Loss of material due to general, pitting, and crevice corrosion	External Surfaces Monitoring	Not Applicable	Not applicable since no GALL AMR line items related to this component group/ aging effect combination were credited in the OCGS LRA.
Steel piping, piping components, and piping elements exposed to air – outdoor (external) (Item 3.3.1-60)	Loss of material due to general, pitting, and crevice corrosion	External Surfaces Monitoring	10 CFR Part 50, Appendix J (B.1.29) plus One-Time Inspection (B.1.24) or One-Time Inspection (B.1.24) or Fire Protection (B.1.19) or Fire Water System (B.1.20) or Structures Monitoring (B.1.31) or Periodic Inspection of Ventilation Systems (B.2.4)	Acceptable since the OCGS 10 CFR Part 50, Appendix J plus one-time inspection, or the one-time inspection, or the fire protection, or the fire water system, or the structures monitoring programs are consistent with the GALL external surfaces monitoring program for this component group/ aging effect combination. The OCGS periodic inspection of ventilation systems program is appropriate for this component group/ aging effect combination. This AMP was reviewed by NRC DE staff. (See Audit Report Section 3.3.2.1.6.3)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Elastomer fire barrier penetration seals exposed to air – outdoor or air – indoor uncontrolled (Item 3.3.1-61)	Increased hardness, shrinkage and loss of strength due to weathering	Fire Protection	Fire Protection (B.1.19) or Structures Monitoring (B.1.31)	Consistent with GALL for AMRs crediting the fire protection program. Acceptable for AMRs crediting the structures monitoring program since the OCGS structures monitoring program is consistent with the GALL fire protection program for this component group/ aging effect combination. (See Audit Report Section 3.3.2.1)
Aluminum piping, piping components, and piping elements exposed to raw water (Item 3.3.1-62)	Loss of material due to pitting and crevice corrosion	Fire Protection	Fire Water System (B.1.20)	Reviewed by NRR/DE Staff.
Steel fire rated doors exposed to air – outdoor or air – indoor uncontrolled (Item 3.3.1-63)	Loss of material due to Wear	Fire Protection	Fire Protection (B.1.19)	Consistent with GALL. (See Audit Report Section 3.3.2.1)
Steel piping, piping components, and piping elements exposed to fuel oil (Item 3.3.1-64)	Loss of material due to general, pitting, and crevice corrosion	Fire Protection and Fuel Oil Chemistry	Fire Protection (B.1.19) and Fuel Oil Chemistry (B.1.20)	Consistent with GALL. (See Audit Report Section 3.3.2.1)
Reinforced concrete structural fire barriers – walls, ceilings and floors exposed to air – indoor uncontrolled (Item 3.3.1-65)	Concrete cracking and spalling due to aggressive chemical attack, and reaction with aggregates	Fire Protection and Structures Monitoring	Fire Protection (B.1.19) and Structures Monitoring (B.1.31)	Consistent with GALL. (See Audit Report Section 3.3.2.1)
Reinforced concrete structural fire barriers – walls, ceilings and floors exposed to air – outdoor (Item 3.3.1-66)	Concrete cracking and spalling due to freeze thaw, aggressive chemical attack, and reaction with aggregates	Fire Protection and Structures Monitoring	Fire Protection (B.1.19) and Structures Monitoring (B.1.31)	Consistent with GALL. (See Audit Report Section 3.3.2.1)
Reinforced concrete structural fire barriers – walls, ceilings and floors exposed to air –	Loss of material due to corrosion of embedded steel	Fire Protection and Structures Monitoring	Fire Protection (B.1.19) and Structures Monitoring (B.1.31)	Consistent with GALL. (See Audit Report Section 3.3.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
outdoor or air – indoor uncontrolled (Item 3.3.1-67)				
Steel piping, piping components, and piping elements exposed to raw water (Item 3.3.1-68)	Loss of material due to general, pitting, crevice, and MIC, and fouling	Fire Water System	Fire Water System (B.1.20)	Consistent with GALL. (See Audit Report Section 3.3.2.1)
Stainless steel piping, piping components, and piping elements exposed to raw water (Item 3.3.1-69)	Loss of material due to pitting and crevice corrosion, and fouling	Fire Water System	Fire Water System (B.1.20)	Consistent with GALL. (See Audit Report Section 3.3.2.1)
Copper alloy piping, piping components, and piping elements exposed to raw water (Item 3.3.1-70)	Loss of material due to pitting, crevice, and MIC, and fouling	Fire Water System	Fire Water System (B.1.20)	Consistent with GALL (See Audit Report Section 3.3.2.1)
Steel piping, piping components, and piping elements exposed to moist air or condensation (Internal) (Item 3.3.1-71)	Loss of material due to general, pitting, and crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Not Applicable	Not applicable since no GALL AMR line items related to this component group/ aging effect combination were credited in the OCGS LRA..
Steel HVAC ducting and components internal surfaces exposed to condensation (Internal) (Item 3.3.1-72)	Loss of material due to general, pitting, crevice, and (for drip pans and drain lines) MIC	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Periodic Inspection of Ventilation Systems (B.2.4)	Reviewed by NRC DE staff. The OCGS periodic inspection of ventilation systems program is appropriate for this component group/ aging effect combination. This AMP was reviewed by NRR/DE staff. (See Audit Report Section 3.3.2.1.6.3)
Steel crane structural girders in load handling system exposed to air – indoor uncontrolled (external) (Item 3.3.1-73)	Loss of material due to general corrosion	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.1.16)	Consistent with GALL. (See Audit Report Section 3.3.2.1)
Steel cranes – rails exposed to air – indoor uncontrolled (external) (Item 3.3.1-74)	Loss of material due to Wear	Inspection of Overhead Heavy Load and Light Load	Inspection of Overhead Heavy Load and Light Load (Related to	Consistent with GALL. (See Audit Report Section 3.3.2.1)

Component Group	**Aging Effect/ Mechanism**	**AMP in GALL Report**	**AMP in LRA**	**Staff Evaluation**
		(Related to Refueling) Handling Systems	Refueling) Handling Systems (B.1.16)	
Elastomer seals and components exposed to raw water (Item 3.3.1-75)	Hardening and loss of strength due to elastomer degradation; loss of material due to erosion	Open-Cycle Cooling Water System	Periodic Inspection (B.2.5)	Reviewed by NRR/DE staff.
Steel piping, piping components, and piping elements (without lining/ coating or with degraded lining/coating) exposed to raw water (Item 3.3.1-76)	Loss of material due to general, pitting, crevice, and MIC, fouling, and lining/coating degradation	Open-Cycle Cooling Water System	Not Applicable	Not applicable since no GALL AMR line items related to this component group/ aging effect combination were credited in the OCGS LRA.
Steel heat exchanger components exposed to raw water (Item 3.3.1-77)	Loss of material due to general, pitting, crevice, galvanic, and MIC, and fouling	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System (B.1.13)	Consistent with GALL. (See Audit Report Section 3.3.2.1)
Stainless steel, nickel alloy, and copper alloy piping, piping components, and piping elements exposed to raw water (Item 3.3.1-78)	Loss of material due to pitting and crevice corrosion	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System (B.1.13) or One-Time Inspection (B.1.24)	Consistent with GALL for AMRs crediting the OCGS open-cycle cooling water system. Acceptable for AMRs crediting the OCGS one-time inspection program since it is consistent with the GALL open-cycle cooling water system program for this component group/ aging effect combination. (See Audit Report Section 3.3.2.1.9)
Stainless steel piping, piping components, and piping elements exposed to raw water (Item 3.3.1-79)	Loss of material due to pitting and crevice corrosion, and fouling	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System (B.1.13)	Consistent with GALL. (See Audit Report Section 3.3.2.1)
Stainless steel and copper alloy piping, piping components, and piping elements	Loss of material due to pitting, crevice, and MIC	Open-Cycle Cooling Water System	Not Applicable	Not applicable since no GALL AMR line items related to this component group/ aging effect

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
exposed to raw water (Item 3.3.1-80)				combination were credited in the OCGS LRA.
Copper alloy piping, piping components, and piping elements, exposed to raw water (Item 3.3.1-81)	Loss of material due to pitting, crevice, and MIC, and fouling	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System (B.1.13) or Periodic Inspection (B.2.5)	Consistent with GALL for AMRs crediting the OCGS open-cycle cooling water system. Reviewed by NRR/DE Staff Periodic inspection program is appropriate for this component group/ aging effect combination. (See Audit Report Section 3.3.2.1.9)
Copper alloy heat exchanger components exposed to raw water (Item 3.3.1-82)	Loss of material due to pitting, crevice, galvanic, and MIC, and fouling	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System (B.1.13) or Fire Water System (B.1.20)	Consistent with GALL for AMRs crediting the OCGS open-cycle cooling water system. Acceptable for AMRs crediting the OCGS fire water system program since it is consistent with the GALL open-cycle cooling water system program for this component group/ aging effect combination. (See Audit Report Section 3.3.2.1.9)
Stainless steel and copper alloy heat exchanger tubes exposed to raw water (Item 3.3.1-83)	Reduction of heat transfer due to fouling	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System (B.1.13)	Consistent with GALL. (See Audit Report Section 3.3.2.1)
Copper alloy > 15% Zn piping, piping components, piping elements, and heat exchanger components exposed to raw water, treated water, or closed cycle cooling water (Item 3.3.1-84)	Loss of material due to selective leaching	Selective Leaching of Materials	Selective Leaching of Materials (B.1.25)	Consistent with GALL. (See Audit Report Section 3.3.2.1)
Gray cast iron piping, piping components, and piping elements exposed to soil, raw	Loss of material due to selective leaching	Selective Leaching of Materials	Selective Leaching of Materials (B.1.25)	Consistent with GALL. (See Audit Report Section 3.3.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
water, treated water, or closed-cycle cooling water (Item 3.3.1-85)				
Structural steel (new fuel storage rack assembly) exposed to air – indoor uncontrolled (external) (Item 3.3.1-86)	Loss of material due to general, pitting, and crevice corrosion	Structures Monitoring Program	Structures Monitoring Program (B.1.31)	Consistent with GALL. (See Audit Report Section 3.3.2.1)
Galvanized steel piping, piping components, and piping elements exposed to air – indoor uncontrolled (Item 3.3.1-92)	None	None	None	Acceptable – No aging management program is needed since no aging effect is identified for this component group. (See Audit Report Section 3.3.2.3.2)
Glass piping elements exposed to air, air – indoor uncontrolled (external), fuel oil, lubricating oil, raw water, treated water, and treated borated water (Item 3.3.1-93)	None	None	None	Acceptable – No aging management program is needed since no aging effect is identified for this component group. (See Audit Report Section 3.3.2.3.2)
Stainless steel and nickel alloy piping, piping components, and piping elements exposed to air – indoor uncontrolled (external) (Item 3.3.1-94)	None	None	None	Acceptable – No aging management program is needed since no aging effect is identified for this component group. (See Audit Report Section 3.3.2.3.2)
Steel and aluminum piping, piping components, and piping elements exposed to air – indoor controlled (external) (Item 3.3.1-95)	None	None	None	Acceptable – No aging management program is needed since no aging effect is identified for this component group. (See Audit Report Section 3.3.2.3.2)
Steel and stainless steel piping, piping components, and piping elements in concrete (Item 3.3.1-96)	None	None	None	Acceptable – No aging management program is needed since no aging effect is identified for this component group. (See Audit Report Section 3.3.2.3.2)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Steel, stainless steel, aluminum, and copper alloy piping, piping components, and piping elements exposed to gas (Item 3.3.1-97)	None	None	None	Acceptable – No aging management program is needed since no aging effect is identified for this component group. (See Audit Report Section 3.3.2.3.2)
Steel, stainless steel, and copper alloy piping, piping components, and piping elements exposed to dried air (Item 3.3.1-98)	None	None	None	Acceptable – No aging management program is needed since no aging effect is identified for this component group. (See Audit Report Section 3.3.2.3.2)

3.3.2.1 *AMR Results That Are Consistent with The GALL Report*

<u>Summary of Information in the Application</u>

For aging management evaluations that the applicant stated are consistent with the GALL Report, the project team conducted its audit and review to determine if the applicant's reference to the GALL Report in the OCGS LRA is acceptable.

In OCGS LRA Section 3.3.1.2.1, the applicant identified the materials, environments, and aging effects requiring management. The applicant identified the following programs that manage the aging effects related to the ?C" battery room heating & ventilation, 4160 V switchgear room ventilation, 480 V switchgear room ventilation, battery and MG set room ventilation, chlorination system, circulating water system, containment inerting system, containment vacuum breakers, control rod drive system, control room HVAC, drywell floor and equipment drains, emergency diesel generator and auxiliary system, emergency service water system, fire protection system, fuel storage and handling equipment, hardened vent system, heating & process steam system, hydrogen & oxygen monitoring system, instrument (control) air system, main fuel oil storage & transfer system, miscellaneous floor and equipment drain system, nitrogen supply system, noble metals monitoring system, post-accident sampling system, process sampling system, radiation monitoring system, radwaste area heating and ventilation system, reactor building closed cooling water system, reactor building floor and equipment drains, reactor building ventilation system, reactor water cleanup system, roof drains and overboard discharge, sanitary waste system, service water system, shutdown cooling system, spent fuel pool cooling system, standby liquid control system (liquid poison system), traveling in-core probe system, turbine building closed cooling water system, and water treatment & distribution system components and component groups:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.1.1)
- Water Chemistry (B.1.2)
- BWR SCC (B.1.7)
- Bolting Integrity (B.1.12)
- OCCWS (B.1.13)

- CCCWS (B.1.14)
- Boraflex Rack Management Program (B.1.15)
- Compressed Air Monitoring (B.1.17)
- BWR RWCU System (B.1.18)
- Fire Protection (B.1.19)
- Fire Water System (B.1.20)
- Aboveground Outdoor Tanks (B.1.21)
- Fuel Oil Chemistry (B.1.22)
- One-Time Inspection (B.1.24)
- Selective Leaching of Materials (B.1.25)
- Buried Piping Inspection (B.1.26)
- ASME Section XI, Subsection IWE (B.1.27)
- 10 CFR Part 50, Appendix J (B.1.29)
- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.1.16)
- Structures Monitoring Program (B.1.31)
- Lubricating Oil Monitoring Activities (B.2.2)
- Periodic Inspection of Ventilation Systems (B.2.4)
- Periodic Inspection Program (B.2.5)

Project Team Evaluation

The project team reviewed its assigned OCGS LRA AMR line-items to determine that the applicant (1) provided a brief description of the system, components, materials, and environment; (2) stated that the applicable aging effects have been reviewed and are evaluated in the GALL Report; and (3) identified those aging effects for the ?C" battery room heating & ventilation, 4160 V switchgear room ventilation, 480 V switchgear room ventilation, battery and MG set room ventilation, chlorination system, circulating water system, containment inerting system, containment vacuum breakers, control rod drive system, control room HVAC, drywell floor and equipment drains, emergency diesel generator and auxiliary system, emergency service water system, fire protection system, fuel storage and handling equipment, hardened vent system, heating & process steam system, hydrogen & oxygen monitoring system, instrument (control) air system, main fuel oil storage & transfer system, miscellaneous floor and equipment drain system, nitrogen supply system, noble metals monitoring system, post-accident sampling system, process sampling system, radiation monitoring system, radwaste area heating and ventilation system, reactor building closed cooling water system, reactor building floor and equipment drains, reactor building ventilation system, reactor water cleanup system, roof drains and overboard discharge, sanitary waste system, service water system, shutdown cooling system, spent fuel pool cooling system, standby liquid control system (liquid poison system), traveling in-core probe system, turbine building closed cooling water system, and water treatment & distribution system components that are subject to an AMR.

3.3.2.1.1 Loss of Material Due to Pitting and Crevice Corrosion

The project team noted that the OCGS LRA, Table 3.3.2.1.18 for the heating and process steam system, includes AMR line items for loss of material in heat exchangers constructed of copper that are exposed to auxiliary steam, and steam traps constructed of copper alloy that are exposed to boiler treated water on the internal surface. The applicant credited the OCGS one-time inspection aging management program (AMP B.1.24) to manage loss of material for these components. The applicant was asked to provide the justification for concluding that the

One-Time Inspection Program alone was sufficient to manage loss of material for these components.

In its letter dated April 17, 2006 (ML061150320), the applicant committed to revise Table 3.3.2.1.18 in the OCGS LRA to include the water chemistry aging management program to address loss of material due to pitting and crevice corrosion for components constructed of copper and copper alloy in the heating and process steam system that are exposed to auxiliary steam and boiler treated water. **This is Audit Commitment 3.3.2.1.1-1.**

The project team reviewed the applicant's response and determined that the addition of the Water Chemistry Program would make these line items consistent with the recommendations in the GALL Report to manage loss of material due to pitting and crevice corrosion, and therefore was acceptable.

The project team found that, by using the Water Chemistry Program together with the One-Time Inspection Program to manage loss of material due to pitting and crevice corrosion, the applicant has demonstrated that the effects of aging will be adequately managed.

The project team also noted that, in the OCGS LRA, Table 3.3.2.1.41 for the water treatment and distribution system included AMR line items for loss of material in valve bodies constructed of brass and bronze that are exposed to treated water on the internal surface. The applicant credited the OCGS selective leaching of materials aging management program (AMP B.1.25) to manage loss of material for these components. The project team reviewed the OCGS Selective Leaching of Materials Program and determined that it manages loss of material due to selective leaching; however, it does not manage loss of material due to pitting and crevice corrosion. The applicant was asked to clarify how loss of material due to pitting and crevice corrosion would be managed for these components.

In its letter dated April 17, 2006 (ML061150320), the applicant committed to revise Table 3.3.2.1.41 in the OCGS LRA to address aging management of loss of material due to pitting and crevice corrosion for valve bodies constructed of brass and bronze exposed to treated water on the internal surface by adding the following AMR line items:

- Valve Body – leakage boundary – brass – treated water (internal) – loss of material – water chemistry (B.1.2) – VII.E4-8 (AP-64) 3.3.1-38
- Valve Body – leakage boundary – brass – treated water (internal) – loss of material – one-time inspection (B.1.24) – VII.E4-8 (AP-64) 3.3.1-38
- Valve Body – leakage boundary – bronze – treated water (internal) – loss of material – water chemistry (B.1.2) – VII.E4-8 (AP-64) 3.3.1-38
- Valve Body – leakage boundary – bronze – treated water (internal) – loss of material – one-time inspection (B.1.24) – VII.E4-8 (AP-64) 3.3.1-38

This is Audit Commitment 3.3.2.1.1-2.

The project team reviewed the applicant's response and determined that the line items to be added were consistent with the recommendations in the GALL Report to manage loss of material due to pitting and crevice corrosion; therefore, they are acceptable.

The project team found that, by using the Water Chemistry Program together with the One-Time Inspection Program to manage loss of material due to pitting and crevice corrosion, the applicant has demonstrated that the effects of aging will be adequately managed.

3.3.2.1.2 Cracking Initiation and Growth Due to Thermal and Mechanical Loading

The project team noted that, in the OCGS LRA, Table 3.3.2.1.9 for the control rod drive system, Table 3.3.2.1.24 for the noble metals monitoring system, Table 3.3.2.1.25 for the post-accident sampling system, Table 3.3.2.1.32 for the reactor water cleanup system, Table 3.3.2.1.36 for the shutdown cooling system, and Table 3.3.2.1.38 for the standby liquid control system included AMR line items for piping, fittings, and valve bodies less than NPS 4 constructed of various materials and exposed to treated water on the internal surface. The applicant credited the OCGS One-Time Inspection Program (AMP B.1.24) to manage cracking initiation and growth due to thermal and mechanical loading of these components. The project team reviewed the applicants One-Time Inspection Program and verified that it is consistent with the recommendations in the GALL Report for AMP XI.M32. The project team determined that this program would provide additional assurance that the aging effects are adequately managed; therefore, it is acceptable. The project team's evaluation of OCGS AMP B.1.24 is discussed in Section 3.0.3.1.4 of this audit and review report.

On the basis of its review, the project team found that the applicant appropriately addressed cracking initiation and growth due to thermal and mechanical loading for components in the control rod drive, post-accident sampling, reactor water cleanup, shutdown cooling, and standby liquid control systems.

3.3.2.1.3 Hardening and Loss of Strength Due to Elastomer Degradation

In the OCGS LRA, Table 3.3.2.1.14 for the emergency service water system, Table 3.3.2.1.17 for the hardened vent system, and Table 3.3.2.1.35 for the service water system, include AMR line items for hardening and loss of strength due to elastomer degradation. The applicant proposed to manage hardening and loss of strength due to elastomer degradation using the OCGS structures monitoring program (AMP B.1.31) for external surfaces of elastomer components exposed to indoor or outdoor air. Generic note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report; however, a different aging management program was credited. The GALL Report recommended a plant specific program be evaluated for this aging effect.

The project team reviewed the applicant's structures monitoring program (AMP B.1.31), and verified that this program includes visual inspections of component external surfaces to detect aging degradation of elastomer components. The project team determined that this AMP is adequate to detect hardening and loss of strength due to elastomer degradation prior to a loss of intended function, and that this AMP will adequately manage this aging effect.

On the basis of its review, the project team found that the applicant appropriately addressed hardening and loss of strength due to elastomer degradation for elastomer components in the emergency service water, hardened vent, and service water systems.

3.3.2.1.4 Cracking Initiation and Growth Due to Stress Corrosion Cracking

3.3.2.1.4.1 Cracking Initiation and Growth due to Stress Corrosion Cracking [Item 1]

In the OCGS LRA, Table 3.3.2.1.24 for the noble metals monitoring system, the applicant proposed to manage cracking initiation and growth due to stress corrosion cracking of stainless steel piping and fittings less than NPS 4 in a treated water environment using the OCGS Water Chemistry Program (AMP B.1.2) together with the OCGS One-Time Inspection Program (AMP

B.1.24). In plant specific note 1 to Table 3.3.2.1.24 in the OCGS LRA, the applicant stated that the BWR reactor water cleanup system program does not apply to piping and piping welds less than NPS 4; therefore, the water chemistry and one-time inspection programs will be used to confirm that cracking due to stress corrosion cracking/intergrannular stress corrosion cracking is not occurring in piping and piping welds less than NPS 4. Generic note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report; however, a different aging management program was credited. The GALL Report recommended the BWR reactor water cleanup system program (XI.M25) for this aging effect.

The project team reviewed the applicant's Water Chemistry Program (AMP B.1.2), One-Time Inspection Program (B.1.24) and verified that these programs are consistent with the recommendations in the GALL Report for AMPs XI.M2 and XI.M32, respectively. The project team also verified that these programs include activities that will mitigate cracking initiation and growth due to stress corrosion cracking in stainless steel components. The project team determined that these programs would provide additional assurance that the aging effects are adequately managed; therefore, it is acceptable.

On the basis of its review, the project team found that the applicant appropriately addressed cracking due to stress corrosion cracking of stainless steel piping and fittings less than NPS 4 for the noble metals monitoring system.

3.3.2.1.4.2 Cracking Initiation and Growth due to Stress Corrosion Cracking [Item 2]

In the OCGS LRA, Table 3.3.2.1.36 for the shutdown cooling system and Table 3.3.2.1.32 for the reactor water cleanup system, the applicant proposed to manage cracking due to stress corrosion cracking of stainless steel piping and fittings greater than or equal to NPS 4 in a treated water environment using the Water Chemistry Program (AMP B.1.2) together with the BWR stress corrosion cracking program (AMP B.1.7) and the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD program (AMP B.1.1). In plant specific notes 1 and 4 to Tables 3.3.2.1.36 and 3.3.2.1.32 in the OCGS LRA, respectively, the applicant stated that the ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD program was applied in addition to the GALL Report recommended programs for this aging effect. Generic note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report; however, a different aging management program was credited. The GALL Report recommended the Water Chemistry Program and the BWR stress corrosion cracking program to manage this aging effect.

The project team reviewed the applicant's Water Chemistry Program (AMP B.1.2) and BWR stress corrosion cracking program (AMP B.1.7) and verified that these programs are consistent with the recommendations in the GALL Report. Therefore, the project team determined that the applicant's proposed inclusion of the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD program, in addition to the GALL recommended programs, will provide additional assurance that this aging effect will be adequately managed, and was acceptable.

On the basis of its review, the project team found that the applicant appropriately addressed cracking due to stress corrosion cracking for stainless steel components in a treated water environment in the reactor water cleanup and shutdown cooling systems.

3.3.2.1.5 Components Exposed to Dry Air with No Aging Effect Identified

In the OCGS LRA, Table 3.3.2.1.20 for the instrument air system, the applicant included AMR line items for various components exposed to a dry gas environment for which no aging effect was identified. The applicant cited the Compressed Air Monitoring program (AMP B.1.17) in these AMR line items. Generic note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report; however, a different aging management program was credited. Plant specific note 1 to Table 3.3.2.1.20 was also cited, in which the applicant stated that the Compressed Air Monitoring program was applied to the instrument air system components to confirm the internal environment remains sufficiently dry to preclude aging effects. The GALL Report does not recommend an aging management program when no aging effect has been identified.

In reviewing these AMR line items, the project team recognized that, in Branch Technical Position RLSB-1, the staff noted that an aging effect should be identified as applicable for license renewal even if there is a prevention or mitigation program associated with that aging effect. Therefore, the applicant was asked to clarify why no aging effect was identified for these components. The applicant responded that the Compressed Air Monitoring Program provides confirmation of the environment, and is not considered a prevention or mitigation program to an aging effect, as defined in NUREG-1800, Rev. 1, Appendix A.1.2.1.5. NUREG-1801, Rev. 1, Chapter IX, Section D, Environments defines the environment of dry air as ?air that has been treated to reduce the dew point well below the system operating temperature." The plant specific note was added to explain why the Compressed Air Monitoring program was included for these line items.

The project team reviewed the applicant's response and determined that the Compressed Air Monitoring program was included to confirm the specified atmosphere; not as a prevention or mitigation program. Therefore, the project team found the AMR line items acceptable.

On the basis of its review, the project team found that the applicant appropriately identified no aging effect for components in the instrument air system exposed to a dry air environment, and the inclusion of the Compressed Air Monitoring program for these AMR line items is acceptable.

3.3.2.1.6 Loss of Material Due to General, Pitting, and Crevice Corrosion

3.3.2.1.6.1 Loss of Material due to General, Pitting, and Crevice Corrosion [Item 1]

In the OCGS LRA, Table 3.3.2.1.1 for the C-battery room heating and ventilation system, Table 3.3.2.1.2 for the 4160V switchgear room ventilation system, Table 3.3.2.1.3 for the 480V switchgear room ventilation system, Table 3.3.2.1.4 for the battery room and MG set room ventilation system, Table 3.3.2.1.8 for the containment vacuum breakers, Table 3.3.2.1.10 for the control room HVAC system, Table 3.3.2.1.11 for the cranes and hoists, Table 3.3.2.1.28 for the radwaste area heating and ventilation system, and Table 3.3.2.1.31 for the reactor building ventilation system, the applicant proposed to manage loss of material due to general, pitting, and crevice corrosion of the external surfaces of structural and closure bolting constructed of carbon and low alloy steel exposed to indoor or outdoor air using the ASME Section XI, Subsection IWE Program (AMP B.1.27), Inspection of Overhead Heavy Load and Light Load Handling System Program (AMP B.1.16), or the Structures Monitoring Program (AMP B.1.31). Generic note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report; however, a different aging management program was credited. The GALL Report recommended the Bolting Integrity Program (AMP XI.M18) for this aging effect.

The project team reviewed the applicant's ASME Section XI, Subsection IWE Program (AMP B.1.27), Inspection of Overhead Heavy Load and Light Load Handling System Program (AMP B.1.16), and the Structures Monitoring Program (AMP B.1.31) and verified that these programs include inspections that will detect loss of material due to general, pitting, and crevice corrosion on the external surfaces of structural and closure bolting. The project team determined that these AMPs were consistent with the Bolting Integrity Program in the GALL Report for detecting loss of material due to general, pitting, and crevice corrosion prior to a loss of intended function for the applications cited, and that these AMPs will adequately manage this aging effect.

On the basis of its review, the project team found that the applicant appropriately addressed loss of material due to general, pitting, and crevice corrosion on the external surfaces of structural and closure bolting exposed to indoor or outdoor air in the auxiliary systems.

3.3.2.1.6.2 Loss of Material due to General, Pitting, and Crevice Corrosion [Item 2]

In the OCGS LRA, Table 3.3.2.1.13 for the emergency diesel generator and auxiliary system, Table 3.3.2.1.26 for the process sampling system, Table 3.3.2.1.29 for the reactor building closed cooling water system, and Table 3.3.2.1.40 for the turbine building closed cooling water system, the applicant proposed to manage loss of material due to general, pitting and crevice corrosion of the internal surfaces of piping, fittings, and tanks constructed of carbon and low alloy steel, and cast iron, exposed to closed cooling water using the closed-cooling water system program (AMP B.1.14) and the One-Time Inspection Program (AMP B.1.24). Generic note E was cited for the One-Time Inspection Program for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report; however, a different aging management program was credited. The GALL Report recommended the closed-cooling water system program (XI.M21) alone for this aging effect. In plant specific notes to the aforementioned tables in the OCGS LRA, the applicant stated that the One-Time Inspection Program was added to the GALL recommended Water Chemistry Program to confirm the absence of this aging effect in stagnant flow areas.

The project team reviewed the applicant's closed-cooling water system program (AMP B.1.14) and verified that it is consistent with the closed-cooling water system program (XI.M21) recommended in the GALL Report to manage this aging effect. The project team determined that the addition of the One-Time Inspection Program would provide additional assurance that this aging effect will be adequately managed, therefore, it is acceptable.

On the basis of its review, the project team found that the applicant appropriately addressed loss of material due to general, pitting, and crevice corrosion on the internal surfaces of piping, fittings and tanks exposed to closed-cooling water in the emergency diesel generator and auxiliary, process sampling, reactor building closed cooling water, and turbine building closed cooling water systems.

3.3.2.1.6.3 Loss of Material due to General, Pitting, and Crevice Corrosion [Item 3]

In the OCGS LRA, Section 3.3.2.2.7.3, the applicant provided its further evaluation for loss of material due to general, pitting, and crevice corrosion for steel piping, piping components, piping elements, ducting, closure bolting and heat exchanger tubes exposed to air-indoor uncontrolled, air-outdoor, condensation, moist air, treated water, or lubricating oil, in accordance with the draft January 2005 SRP-LR.

In reviewing this further evaluation, the project team recognized that the approved September 2005 GALL Report recommended AMP XI.M36 XI.M38, ?Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components,"or XI.M39,?Lubricating Oil Analysis" to manage this aging effect with no further evaluation required. Therefore, the project team reviewed the applicant's further evaluation against the recommendations in the aforementioned GALL AMPs, as appropriate.

In the OCGS LRA, Section 3.3.2.2.7.3, the applicant stated that Oyster Creek will implement a One-Time Inspection Program, B.1.24, for susceptible locations to verify the effectiveness of the 10 CFR Part 50, Appendix J program, B.1.29, to manage the loss of material in primary containment boundary steel piping, piping components, and piping elements exposed to an indoor air internal environment in the reactor water cleanup system and reactor building ventilation system. The 10 CFR Part 50, Appendix J program provides for the detection of age related degradation due to loss of material. The program consists of tests performed in accordance with the regulations and guidance provided in 10 CFR Part 50 Appendix J, Option B and station procedures. Containment leak rate tests are performed to assure that leakage through the primary containment and systems and components penetrating primary containment does not exceed allowable leakage limits specified in the technical specifications. An integrated leak rate test (ILRT) is performed during a period of reactor shutdown at the frequency specified in 10 CFR Part 50, Appendix J, Option B. Local leak rate tests (LLRT) are performed on isolation valves and containment access penetrations at frequencies that comply with the requirements of 10 CFR Part 50 Appendix J, Option B. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's 10 CFR Part 50, Appendix J program (AMP B.1.29) and verified that this aging management program included activities that are consistent with the recommendations in GALL AMP XI.M36 to manage loss of material in components exposed to an indoor air internal environment. In addition, the project team reviewed the applicant's One-Time Inspection Program (B.1.24) and verified that this aging management program includes inspections of components to detect loss of material as a means of verifying the effectiveness of the 10 CFR Part 50, Appendix J program. The project team determined that OCGS AMPs B.1.29 and B.1.24, together, will adequately manage loss of material in primary containment boundary steel piping, piping components, and piping elements exposed to an indoor air internal environment in the reactor water cleanup system and reactor building ventilation system.

In the OCGS LRA, Section 3.3.2.2.7.3, the applicant stated that Oyster Creek will implement a fire protection program, B.1.19, to inspect the internal surfaces of steel piping, piping components, and piping elements with an indoor air internal environment for halon/carbon dioxide fire suppression systems. The program provides for periodic system operability testing and visual aging degradation inspections of internal surfaces that ensure aging degradation is detected prior to the loss of intended function. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's fire protection program (AMP B.1.19) and verified that this aging management program included activities that are consistent with the recommendations in GALL AMP XI.M38 to manage loss of material in components with an indoor air internal environment. The project team determined that OCGS AMP B.1.19 will adequately manage loss of material in steel piping, piping components, and piping elements with an indoor air internal environment for halon/carbon dioxide fire suppression systems.

In the OCGS LRA, Section 3.3.2.2.7.3, the applicant stated that Oyster Creek will implement a fire water system program, B.1.20, to inspect the internal surfaces of steel piping, piping components, and piping elements with an indoor air internal environment for water-based fire protection systems. Program activities include system monitoring, periodic inspections, surveillance testing, and system maintenance activities that ensure aging degradation is detected prior to the loss of intended function. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's fire water system program (AMP B.1.20) and verified that this aging management program included activities that are consistent with the recommendations in GALL AMP XI.M38 to manage loss of material on the internal surfaces of components with an indoor air internal environment. The project team determined that OCGS AMP B.1.20 will adequately manage loss of material on the internal surfaces of steel piping, piping components, and piping elements with an indoor air internal environment for water-based fire protection systems

In the OCGS LRA, Section 3.3.2.2.7.3, the applicant stated that Oyster Creek will implement a One-Time Inspection Program, B.1.24, for susceptible locations to verify the effectiveness of the generator stator water chemistry activities program, B.2.3, to manage the loss of material in steel piping, piping components, piping elements, and heat exchangers exposed to a treated water internal environment in the main generator and auxiliary system. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's further evaluation and determined that the generator stator water chemistry activities program (AMP B.2.3) is a plant specific program that is appropriate to manage the loss of material in steel piping, piping components, piping elements, and heat exchangers. The technical evaluation of this program to determine its adequacy was performed by NRR/DE staff, and is addressed in the SER related to the Oyster Creek plant. In addition, the project team reviewed the applicant's One-Time Inspection Program (B.1.24) and verified that this aging management program includes inspections of steel piping, piping components, piping elements, and heat exchangers to detect loss of material as a means of verifying the effectiveness of the generator stator water chemistry activities program.

In the OCGS LRA, Section 3.3.2.2.7.3, the applicant stated that Oyster Creek will implement a Periodic Inspection Program, B.2.5, to manage the loss of material in emergency diesel generator ventilation system steel components exposed to an indoor air internal or external environment or an oil external environment. The Periodic Inspection Program will also be used to manage the loss of material in emergency diesel generator ventilation system ductwork exposed to an indoor air internal environment. The Periodic Inspection Program relies on periodic inspections to identify and evaluate the degradation of steel components exposed to an indoor air internal or external environment or an oil external environment to ensure that there is no loss of intended function. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's further evaluation and determined that the Periodic Inspection Program (AMP B.2.5) is a plant specific program that is appropriate to manage the loss of material in emergency diesel generator ventilation system steel components exposed to an indoor air internal or external environment or an oil external environment. The technical evaluation of this program to determine its adequacy was performed by NRR/DE staff, and is addressed in the SER related to the Oyster Creek plant.

In the OCGS LRA, Section 3.3.2.2.7.3, the applicant stated that Oyster Creek will implement a periodic inspection of ventilation systems program, B.2.4, to manage the loss of material in ventilation system steel piping, piping components, and piping elements exposed to an indoor air internal or external environment in the ?C" battery room heating and ventilation system, 480V switchgear room ventilation system, battery and MG set room ventilation system, control room HVAC system, radwaste area heating and ventilation system, and reactor building ventilation system. The program will inspect internal and external steel surfaces of ventilation system components to identify and assess aging effects that may be occurring. The program will include surface inspections of steel components for indications of loss of material, such as rust, corrosion, and pitting. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's further evaluation and determined that the periodic inspection of ventilation systems program (AMP B.2.4) is a plant specific program that is appropriate to manage the loss of material in ventilation system steel piping, piping components, and piping elements exposed to an indoor air internal or external environment. The technical evaluation of this program to determine its adequacy was performed by NRC DE staff, and is addressed in the SER related to the Oyster Creek plant.

In the OCGS LRA, Section 3.3.2.2.7.3, the applicant stated that Oyster Creek will implement a structures monitoring program, B.1.31, to inspect the external surfaces of steel piping, piping components, piping elements, and ductwork exposed to an indoor air external or outdoor air external environment in the emergency diesel generator and auxiliary system, chlorination system, and control room HVAC system. The structures monitoring program relies on periodic visual inspections by qualified individuals to identify and evaluate the degradation of piping, piping components, and piping elements to ensure that there is no loss of intended function. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's structures monitoring program (AMP B.1.31) and verified that this aging management program included activities that are consistent with GALL AMP XI.M36 to manage the loss of material in components exposed to an indoor or outdoor air external environment. The project team determined that OCGS AMP B.1.31 will adequately manage the loss of material on the external surfaces of steel piping, piping components, piping elements, and ductwork exposed to an indoor air external or outdoor air external environment in the emergency diesel generator and auxiliary system, chlorination system, and control room HVAC system.

In the OCGS LRA, Section 3.3.2.2.7.3, the applicant stated that at Oyster Creek, the aging effect of loss of material due to general corrosion in the primary containment atmosphere is not considered a credible aging effect for carbon steel components in a containment nitrogen environment because of negligible amounts of free oxygen (less than 4 percent by volume during normal operation). Both oxygen and moisture must be present for general corrosion to occur because oxygen alone or water free of dissolved oxygen (high humidity in a nitrogen atmosphere) does not corrode carbon steel to any practical extent. Therefore, there is no loss of material for carbon steel components exposed to a containment nitrogen environment because, with the negligible amounts of free oxygen, anodic reactions do not take place and the corrosion cell does not form.

The project team reviewed the applicant's further evaluation related to loss of material due to general corrosion in the primary containment atmosphere for carbon steel components and concurred with the applicant's conclusion that this is not a credible aging effect. The Oyster Creek containment is inerted during normal operation; therefore, there are negligible amounts of free oxygen present. Since oxygen and moisture must be present for general corrosion to occur, general corrosion of carbon steel components is not a credible event.

On the basis of its review, the project team found that the applicant appropriately addressed loss of material due to general, pitting, and crevice corrosion for steel piping, piping components, piping elements, ducting, closure bolting and heat exchanger tubes exposed to air-indoor uncontrolled, air-outdoor, condensation, moist air, treated water, or lubricating oil in the aforementioned auxiliary systems.

3.3.2.1.7 Loss of Preload Due to Stress Relaxation

In the OCGS LRA, Table 3.3.2.1.8 for containment vacuum breakers, Table 3.3.2.1.11 for cranes and hoists, and Table 3.3.2.1.16 for fuel storage and handling equipment, the applicant proposed to manage loss of preload due to stress relaxation of structural and closure bolting constructed of carbon and low alloy steel exposed to indoor air using the ASME Section XI, Subsection IWE program (AMP B.1.27) and the inspection of overhead heavy load and light load handling system program (AMP B.1.16). Generic note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report; however, a different aging management program was credited. The GALL Report recommended the Bolting Integrity Program (AMP XI.M18) for this aging effect.

The project team reviewed the applicant's ASME Section XI, Subsection IWE program (AMP B.1.27) and inspection of overhead heavy load and light load handling system program (AMP B.1.16), and verified that these programs include activities that will detect loss of preload due to stress relaxation of structural and closure bolting. The project team determined that these AMPs will assure detection of loss of preload due to stress relaxation prior to a loss of intended function, and that these AMPs will adequately manage this aging effect.

On the basis of its review, the project team found that the applicant appropriately addressed loss of preload due to stress relaxation of structural and closure bolting exposed to indoor air in the aforementioned auxiliary systems.

3.3.2.1.8 Loss of Material Due to Pitting, Crevice, and Galvanic Corrosion

In the OCGS LRA, Table 3.3.2.1.29 for the reactor building closed cooling water system, the applicant proposed to manage loss of material due to pitting, crevice, and galvanic corrosion of the internal surfaces of the shutdown cooling pump coolers constructed of copper exposed to treated water using the Water Chemistry Program (AMP B.1.2) and the One-Time Inspection Program (AMP B.1.24). In plant specific note 5 to Table 3.3.2.1.29 in the OCGS LRA, the applicant stated that the closed-cooling water system program does not apply to a treated water environment; therefore, the appropriate programs for managing the identified aging effects are water chemistry and one-time inspection. Generic note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report; however, a different aging management program was credited.

As part of its reconciliation of the AMPs in the draft January 2005 GALL Report with the approved September 2005 GALL Report, the applicant determined that the recommendations in the GALL Report for this aging effect were revised. Previously, the GALL Report recommended the closed-cooling water system program (AMP XI.M21); however, the approved September 2005 GALL Report now recommends the Water Chemistry Program (XI.M2) and the One-Time Inspection Program (XI.M32) for this aging effect. Therefore, the applicant concluded that its AMR was consistent with the GALL Report.

The project team reviewed the applicant's Water Chemistry Program (AMP B.1.2) and One-Time Inspection Program (AMP B.1.24), and verified that these programs are consistent with the recommendations in the GALL Report. The project team determined that these AMR line items are consistent with the recommendations in the GALL Report and the applicant's AMPs will adequately manage this aging effect.

On the basis of its review, the project team found that the applicant appropriately addressed loss of material due to pitting, crevice, and galvanic corrosion on the internal surfaces of the shutdown cooling pump coolers.

3.3.2.1.9 Loss of Material Due to Pitting, Crevice, and Microbiologically Influenced Corrosion, and Fouling

In the OCGS LRA, Table 3.3.2.1.6 for the circulating water system, Table 3.3.2.1.15 for the fire protection system, Table 3.3.2.1.22 for the miscellaneous floor and equipment drain system, Table 3.3.2.1.30 for the reactor building floor and equipment drains, and Table 3.3.2.1.34 for the sanitary waste system, the applicant proposed to manage loss of material due to pitting, crevice, and MIC, and fouling, of the internal surfaces of piping and fittings constructed of carbon and low alloy steel, cast iron, copper alloy, bronze and brass exposed to raw water-salt water or raw water-fresh water using the fire water system program (AMP B.1.20), the One-Time Inspection Program (AMP B.1.24), or the Periodic Inspection Program (AMP B.2.5). Generic note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report; however, a different aging management program was credited. The GALL Report recommended the open-cycle cooling water system program (AMP XI.M20) for this aging effect.

The project team reviewed the applicant's Fire Water System Program (AMP B.1.20) and the One-Time Inspection Program (AMP B.1.24), and verified that these programs include activities that will detect loss of material due to pitting, crevice, and MIC, and fouling, on the internal surfaces of piping and fittings. The project team determined that these AMPs are adequate to detect loss of material due to pitting, crevice, and MIC, and fouling, prior to a loss of intended function, and that these AMPs will adequately manage this aging effect.

The project team reviewed applicant's the Periodic Inspection Program (AMP B.2.5) and determined that it is a plant specific program that is appropriate to manage the loss of material due to pitting, crevice, and MIC, and fouling, on the internal surfaces of piping and fittings. The technical evaluation of this program to determine its adequacy was performed by NRR/DE staff, and is addressed in the SER related to the Oyster Creek plant.

On the basis of its review, the project team found that the applicant appropriately addressed loss of material due to pitting, crevice, and MIC, and fouling, on the internal surfaces of piping and fittings exposed to raw water-salt water in the circulating water, fire protection, miscellaneous floor and equipment drain, reactor building floor and equipment drains, and sanitary waste systems.

3.3.2.1.10 Loss of Material Due to General Corrosion

In the OCGS LRA, Section 3.3.2.2.6, the applicant provided its further evaluation for loss of material of steel piping, bolting, and component external surfaces exposed to air-indoor uncontrolled (external), air-outdoor (external), or condensation (external) due to general corrosion, in accordance with the draft January 2005 SRP-LR.

In reviewing this further evaluation, the project team recognized that the approved September 2005 GALL Report recommended aging management program XI.M36 to manage this aging effect with no further evaluation required. Therefore, the project team reviewed the applicant's further evaluation against the recommendations in GALL AMP XI.M36 to manage this aging effect.

In the OCGS LRA, Section 3.3.2.2.6, the applicant stated that Oyster Creek will implement a Fire Protection Program, B.1.19, to inspect the internal and external surfaces of steel piping, piping components, and piping elements exposed to an indoor air internal or external environment, or an outdoor air external environment, for halon/carbon dioxide fire suppression systems. The program provides for periodic system operability testing and visual aging degradation inspections of internal and external surfaces that ensure aging degradation is detected prior to the loss of intended function. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's Fire Protection Program (AMP B.1.19) against the recommendations in GALL AMP XI.M36. The applicant was asked to clarify the frequency of the inspections to be performed under OCGS AMP B.1.19; when the inspections will be initiated; and how inspections of insulated components and inaccessible components will be performed. The applicant stated that the inspections will be performed every 18 months. Some of the inspections are ongoing; however, the enhanced inspections for license renewal will be initiated prior to period of extended operation. The applicant further stated that none of the components in the scope of these inspections are insulated. With regard to inaccessible locations, the applicant stated that NFPA 25 (national fire protection association standard 25 for inspection, testing, and maintenance of water-based fire protection systems) allows an exception from inspection for pipe in concealed spaces or other inaccessible areas. Most of the components included in the scope of these inspections are accessible, and there is sufficient accessible piping to provide a representative assessment of the degree of external surface degradation. The project team reviewed the applicant's response and determined that it is acceptable since it is consistent with the recommendations in GALL AMP XI.M36.

The project team determined that OCGS AMP B.1.19 included inspections that will detect loss of material due to general corrosion that are consistent with the recommendations in the external surfaces monitoring program in the GALL Report (AMP XI.M36). The project team determined that this AMP will adequately manage loss of material due to general corrosion for internal and external surfaces of steel piping, piping components, and piping elements exposed to an indoor air internal or external environment, or an outdoor air external environment, for halon/carbon dioxide fire suppression systems.

In the OCGS LRA, Section 3.3.2.2.6, the applicant stated that Oyster Creek will implement a fire water system program, B.1.20, to inspect the external surfaces of steel piping, piping components, and piping elements exposed to an indoor air external or outdoor air external environment for water-based fire protection systems. Program activities include system monitoring, periodic inspections, surveillance testing, and system maintenance activities that ensure aging degradation is detected prior to the loss of intended function. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process. The Fire Water System Program is described in Appendix B.

The project team reviewed the Applicant's Fire Water System Program (AMP B.1.20) against the recommendations in GALL AMP XI.M36. The applicant was asked to clarify the frequency of the inspections to be performed under OCGS AMP B.1.20; when the inspections will be initiated; and how inspections of insulated components and inaccessible components will be performed. The applicant stated that the external surfaces of the spray and sprinkler systems in the scope of license renewal are visually inspected every 12 months. The condenser bay sprinkler system is located in a high radiation area and is inspected every 24 months. Fire hydrant external surfaces are visually inspected every 6 months. Some of the inspections are ongoing; however, the enhanced inspections for license renewal will be initiated prior to the period of extended operation. The applicant further stated that none of the components in the scope of these inspections are insulated. With regard to inaccessible locations, the applicant stated that NFPA 25 (national fire protection association standard 25 for inspection, testing, and maintenance of water-based fire protection systems) allows an exception from inspection for pipe in concealed spaces or other inaccessible areas. Most of the components included in the scope of these inspections are accessible, and there is sufficient accessible piping to provide a representative assessment of the degree of external surface degradation. The project team reviewed the applicant's response and determined that it is acceptable since it is consistent with the recommendations in GALL AMP XI.M36.

The project team determined that OCGS AMP B.1.20 included inspections that will detect loss of material due to general corrosion that are consistent with the recommendations in the external surfaces monitoring program in the GALL Report (AMP XI.M36). The project team determined that this AMP will adequately manage loss of material due to general corrosion for external surfaces of steel piping, piping components, and piping elements exposed to an indoor air external or outdoor air external environment for water-based fire protection systems.

In the OCGS LRA, Section 3.3.2.2.6, the applicant stated that Oyster Creek will implement a periodic inspection of ventilation systems program, B.2.4, to inspect the internal and external surfaces of steel piping, piping components, piping elements, and ventilation equipment exposed to an indoor air internal or external environment, or an outdoor air external environment in the 480V switchgear room ventilation system, battery and MG set room ventilation system, radwaste area heating and ventilation system and reactor building ventilation system. The program will inspect internal and external steel surfaces of ventilation system components to identify and assess aging effects that may be occurring. The program will include surface inspections of steel components for indications of loss of material, such as rust, corrosion, and pitting. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's further evaluation and determined that the periodic inspection of ventilation systems program (AMP B.2.4) is a plant specific program that is appropriate to inspect the internal and external surfaces of steel piping, piping components, piping elements, and ventilation equipment exposed to an indoor air internal or external environment, or an outdoor air external environment. The technical evaluation of this program to determine its adequacy was performed by NRR/DE staff, and is addressed in the SER related to the Oyster Creek plant.

In the OCGS LRA, Section 3.3.2.2.6, the applicant stated that Oyster Creek will implement a structures monitoring program, B.1.31, to inspect the external surfaces of steel piping, piping components, and piping elements in an indoor air external or outdoor air external environment in the chlorination system, circulating water system, containment inerting system, control rod drive system, drywell floor and equipment drains, emergency diesel generator and auxiliary system, emergency service water system, fire protection system (dikes only), hardened vent system, instrument (control) air system, main fuel oil storage & transfer system, miscellaneous floor and equipment drain system, nitrogen supply system, primary containment, process sampling system, reactor building closed cooling water system, reactor building floor and equipment drains, reactor building ventilation system, reactor head cooling system, reactor recirculation system, reactor water cleanup system, roof drains and overboard discharge, sanitary waste system, service water system, shutdown cooling system, spent fuel pool cooling system, standby liquid control system (liquid poison system), turbine building closed cooling water system, and water treatment & distribution system. The structures monitoring program relies on periodic visual inspections by qualified individuals to identify and evaluate the degradation of piping, piping components, and piping elements to ensure that there is no loss of intended function. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's Structures Monitoring Program (AMP B.1.31) against the recommendations in GALL AMP XI.M36. The applicant was asked to clarify when the inspections to be performed under OCGS AMP B.1.31 will be initiated; and how inspections of inaccessible components will be performed. The applicant stated that some of the inspections are ongoing; however, the enhanced inspections for license renewal will be initiated prior to the period of extended operation. The applicant further stated that inaccessible components will not be routinely inspected. There are sufficient accessible components to provide a representative assessment of the degree of external surface degradation. Degraded conditions identified as a result of these inspections will be evaluated using the Oyster Creek corrective actions process, which will evaluate extent of condition including consideration of inaccessible locations. The project team reviewed the applicant's response and determined that it is acceptable since it is consistent with the recommendations in GALL AMP XI.M36.

The project team determined that OCGS AMP B.1.31 included inspections that will detect loss of material due to general corrosion that are consistent with the recommendations in the external surfaces monitoring program in the GALL Report (AMP XI.M36). The project team determined that this AMP will adequately manage loss of material due to general corrosion for external surfaces of steel piping, piping components, and piping elements in an indoor air external or outdoor air external environment in the chlorination system, circulating water system, containment inerting system, control rod drive system, drywell floor and equipment drains, emergency diesel generator and auxiliary system, emergency service water system, fire protection system (dikes only), hardened vent system, instrument (control) air system, main fuel oil storage & transfer system, miscellaneous floor and equipment drain system, nitrogen supply system, primary containment, process sampling system, reactor building closed cooling water system, reactor building floor and equipment drains, reactor building ventilation system, reactor head cooling system, reactor recirculation system, reactor water cleanup system, roof drains and overboard discharge, sanitary waste system, service water system, shutdown cooling system, spent fuel pool cooling system, standby liquid control system (liquid poison system), turbine building closed cooling water system, and water treatment & distribution system.

In the OCGS LRA, Section 3.3.2.2.6, the applicant stated that at Oyster Creek, the aging effect of loss of material due to general corrosion in the primary containment atmosphere is not considered a credible aging effect for carbon steel components in a containment nitrogen environment because of negligible amounts of free oxygen (less than 4 percent by volume during normal operation). Both oxygen and moisture must be present for general corrosion to occur because oxygen alone or water free of dissolved oxygen (high humidity in a nitrogen atmosphere) does not corrode carbon steel to any practical extent. Therefore, there is no loss of material for carbon steel components exposed to a containment nitrogen environment because, with the negligible amounts of free oxygen, anodic reactions do not take place and the corrosion cell does not form.

The project team reviewed the applicant's further evaluation related to loss of material due to general corrosion in the primary containment atmosphere for carbon steel components and concurred with the applicant's conclusion that this is not a credible aging effect. The Oyster Creek containment is inerted during normal operation; therefore, there are negligible amounts of free oxygen present. Since oxygen and moisture must be present for general corrosion to occur, general corrosion of carbon steel components is not a credible event.

On the basis of its review, the project team found that the applicant appropriately addressed loss of material of steel piping, bolting, and component external surfaces exposed to air-indoor uncontrolled (external), air-outdoor (external), or condensation (external) due to general corrosion.

3.3.2.1.11 Loss of Material Due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion

In the OCGS LRA, Section 3.3.2.2.8.2, the applicant provided its further evaluation for loss of material in the internal surfaces of steel ventilation system exposed to condensation due to general, pitting, crevice, and MIC, in accordance with the draft January 2005 SRP-LR.

In reviewing this further evaluation, the project team recognized that the approved September 2005 GALL Report recommended aging management program XI.M38, ?Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" to manage this aging effect with no further evaluation required. Therefore, the project team reviewed the applicant's further evaluation against the recommendations in GALL AMP XI.M38 to manage this aging effect.

In the OCGS LRA, the applicant stated that at Oyster Creek, ventilation system components in the scope of license renewal are not subject to internal condensation. A review of the maintenance history of these components has not identified degradation due to the presence of internal condensation. Preventive maintenance activities and system manager walkdowns have not identified or reported internal condensation or resulting internal ventilation system degradation in these components. Therefore, the internal environment for ventilation system components in the scope of license renewal does not include condensation. This applies to the following ventilation systems: ?C" battery room heating and ventilation system, 480V switchgear room ventilation system, 4160V switchgear room ventilation system, battery and MG set room ventilation system, control room HVAC system, radwaste area heating and ventilation system, and reactor building ventilation system.

In the OCGS LRA, the applicant further stated that Oyster Creek will implement a Periodic Inspection Program, B.2.5, to manage the loss of material in non-ventilation system steel piping, piping components, and piping elements exposed to a condensation internal environment in the containment inerting system and the emergency diesel generator and auxiliary system. The Periodic Inspection Program includes periodic condition monitoring examinations to assure that existing environmental conditions are not resulting in material degradation that could result in the loss of system intended functions. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's further evaluation and determined that the Periodic Inspection Program (AMP B.2.5) is a plant specific program that is appropriate to manage the loss of material in non-ventilation system steel piping, piping components, and piping elements exposed to a condensation internal environment. The technical evaluation of this program to determine its adequacy was performed by NRR/DE staff, and is addressed in the SER related to the Oyster Creek plant.

On the basis of its review, the project team found that the applicant appropriately addressed loss of material in the internal surfaces of steel ventilation system exposed to condensation due to general, pitting, crevice, and MIC.

3.3.2.1.12 Reduction of Heat Transfer Due to Fouling

In the OCGS LRA, Table 3.3.2.1.13 for the emergency diesel generator and auxiliary system includes AMR line items for the lube oil cooler and radiator heat exchangers exposed to closed-cycle cooling water. The project team noted that the aging effect for reduction of heat transfer due to fouling is not addressed. The applicant was asked to clarify why this aging effect was not identified for these components.

In Attachment 7, Item AP-80 of its reconciliation document, the applicant stated that the emergency diesel generator and auxiliary system brass lube oil cooler and radiator tubes exposed to a closed cooling water environment do not include the reduction of heat transfer aging effect based on industry standards. In these standards, fouling is not identified as a significant aging effect for copper alloy heat exchangers in a closed cooling water environment. Addition of this line item to the emergency diesel generator and auxiliary system AMR is required.

In its letter dated April 17,2006 (ML061150320), the applicant committed to revise Table 3.3.2.1.13 in the OCGS LRA for the emergency diesel generator and auxiliary system to address the aging effect for reduction of heat transfer due to fouling for the brass lube oil cooler and radiator tubes exposed to a closed cooling water environment by crediting the OCGS closed-cycle cooling water program (AMP B.1.14). **This is Audit Commitment 3.3.2.1.12-1.**

The project team reviewed the applicant's commitment and determined that the addition of line items to address reduction of heat transfer due to fouling using the closed-cycle cooling water program (AMP B.1.14) is consistent with the recommendations in the GALL Report, and is acceptable.

Conclusion

The project team has evaluated the applicant's claim of consistency with the GALL Report. The project team also has reviewed the above commitments and information pertaining to the applicant's consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the project team found that the AMR results, which the applicant claimed to be consistent with the GALL Report, are consistent with the AMRs in the GALL Report.

3.3.2.2 *AMR Results For Which Further Evaluation Is Recommended By The GALL Report*

Summary of Information in the Application

In OCGS LRA Section 3.3.2.2, the applicant provided further evaluation of aging management as recommended by the GALL Report for the ?C" battery room heating & ventilation, 4160 V switchgear room ventilation, 480 V switchgear room ventilation, battery and MG set room ventilation, chlorination system, circulating water system, containment inerting system, containment vacuum breakers, control rod drive system, control room HVAC, drywell floor and equipment drains, emergency diesel generator and auxiliary system, emergency service water system, fire protection system, fuel storage and handling equipment, hardened vent system, heating & process steam system, hydrogen & oxygen monitoring system, instrument (control) air system, main fuel oil storage & transfer system, miscellaneous floor and equipment drain system, nitrogen supply system, noble metals monitoring system, post-accident sampling system, process sampling system, radiation monitoring system, radwaste area heating and ventilation system, reactor building closed cooling water system, reactor building floor and equipment drains, reactor building ventilation system, reactor water cleanup system, roof drains and overboard discharge, sanitary waste system, service water system, shutdown cooling system, spent fuel pool cooling system, standby liquid control system (liquid poison system), traveling in-core probe system, turbine building closed cooling water system, and water treatment & distribution system components and component groups. The applicant also provided information concerning how it will manage the related aging effects.

Project Team Evaluation

For some AMR line-items assigned to the project team in Table 3.3.1 of the OCGS LRA, the GALL Report recommends further evaluation. When further evaluation was recommended, the project team reviewed these further evaluations provided in OCGS LRA Section 3.3.2.2 against the criteria provided in the SRP-LR Section 3.3.2.2. The project team's assessment of these evaluations is documented in this section. These assessments are applicable to each Table 2 AMR line-item in Section 3.3 citing the item in Table 1.

3.3.2.2.1 Cumulative Fatigue Damage

In LRA Section 3.3.2.2.1, the applicant stated that fatigue is a TLAA, as defined in 10 CFR 54.3. Applicants must evaluate TLAAs in accordance with 10 CFR 54.21(c)(1).

The project team noted that the OCGS LRA contains numerous AMR line items with references to TLAAs. All but a few cite cumulative fatigue damage as the aging effect requiring management, however it is not clear whether a CLB fatigue analysis actually exists or whether the TLAA is addressed by the assumed 7,000 cycles in accordance with B31.1 or equivalent design methods. The applicant was asked to identify the applicable disposition for each TLAA line item related to cumulative fatigue damage of mechanical components.

In its response, the applicant stated that there are two categories of fatigue TLAAs identified in the AMR tables. The first category is for components for which an explicit fatigue analysis exists, such as one performed in accordance with ASME Section III, Class 1 rules (or equivalent), with an associated Cumulative Usage Factor (CUF) value. The second category is for components that were designed in accordance with implicit fatigue design rules from ANSI B31.1 (or equivalent). The applicant provided a table that identifies whether a system or component has an explicit (E) or implicit (I) fatigue analysis associated with it.

The applicant further stated that, for license renewal, additional explicit fatigue analyses were prepared to consider the effects of environmental fatigue for the components identified in NUREG/CR-6260. These components are denoted in the table as also having an explicit environmental (E-env) fatigue analysis in addition to the original analysis. The components within each system bounded by the applicable environmental fatigue analysis are also denoted with a (E-env) in the table.

The applicant further stated that the table also includes a column denoting the disposition method used to manage the TLAA for the period of extended operation. The notation (I) indicates the existing analysis was determined to remain valid for the period of extended operation. The notation (ii) indicates the analysis was revised to become valid for the period of extended operation. The notation (iii) indicates fatigue monitoring will be used to assure the fatigue analysis will remain valid during the period of extended operation or will be reanalyzed as necessary prior to exceeding the design limit.

The project team reviewed the applicant's response, along with the table that identifies whether the TLAAs are implicit or explicit, and found it acceptable since it clarifies which TLAAs are based on an explicit calculation.

The evaluation of the TLAAs was performed by NRR/DE staff and is addressed separately in Section 4 of the SER related to the OCGS LRA.

3.3.2.2.2 Reduction of Heat Transfer Due to Fouling

The applicant addressed reduction of heat transfer due to fouling in Attachment 3, Item AP-62 of its reconciliation document. Therefore, the project team reviewed that evaluation against the criteria in SRP-LR Section 3.3.2.2.2.

SRP-LR Section 3.3.2.2.2 stated that reduction of heat transfer due to fouling could occur for stainless steel heat exchanger tubes exposed to treated water. The existing program relies on control of water chemistry to manage reduction of heat transfer due to fouling. However, control of water chemistry may have been inadequate. Therefore, the GALL Report recommends that the effectiveness of the water chemistry control program should be verified to ensure that reduction of heat transfer due to fouling is not occurring. A one-time inspection is an acceptable method to ensure that reduction of heat transfer is not occurring and that the component's intended function will be maintained during the period of extended operation.

In Attachment 3, item AP-62 of its reconciliation document, the applicant stated that the SRP-LR line item for stainless steel heat exchanger tubes in treated water, addressing reduction of heat transfer due to fouling, recommended the Water Chemistry Program with no further evaluation required in January 2005, and has been changed in September 2005 to recommend both the water chemistry and one-time inspection programs, with an evaluation of aging effects. There are 2 instances of this line item being used in the LRA that are applicable to the treated water side of heat exchanger components in the reactor building closed cooling water system (RBCCW).

The applicant further stated that, in the Oyster Creek LRA, there are 229 line item instances of one-time inspection of stainless steel components in a treated water environment. While these instances are applied to aging effects of loss of material or cracking, they provide ample inspection opportunity for the condition of the components. Observed conditions that have the potential for impacting an intended function are evaluated and corrected, as necessary, in accordance with the corrective action process. Since one of the functions of the Water Chemistry Program is to prevent reduction of heat transfer due to fouling, a noted fouling condition on any of the inspected items would be identified and entered into the corrective action process. Thus, there is high confidence that any instance of the Water Chemistry Program's failure to prevent fouling would be identified during the inspections for loss of material due to corrosion and cracking. In addition, for the shutdown cooling system heat exchangers invoking this line item, the treated water environment is reactor coolant. The Water Chemistry Program requirements for reactor quality water provide added assurance that an environment conducive to fouling does not exist. The applicant concluded that there is no change required to the OCGS LRA due to this item.

The project team reviewed the applicants reconciliation document, as well as Table 3.3.2.1.29 in the OCGS LRA for the reactor building closed cooling water system. The project team noted that the one-time inspection is cited to manage loss of material for the stainless steel heat exchanger components exposed to treated water in this system; therefore, although the one-time inspection is not noted for the AMR that addresses the reduction of heat transfer aging effect, it is credited as part of the aging management for loss of material. On this basis, the project team determined that the applicant is adequately managing reduction of heat transfer due to fouling for stainless steel heat exchanger components exposed to treated water in the RBCCW system, and no change is required to the OCGS LRA.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.3.2.2.2 for further evaluation.

3.3.2.2.3 Cracking Due to Stress Corrosion Cracking

3.3.2.2.3.1 Cracking Due to Stress Corrosion Cracking [Item 1]

The project team reviewed OCGS LRA Section 3.3.2.2.3.1 against the criteria in SRP-LR Section 3.3.2.2.3.1.

SRP-LR Section 3.3.2.2.3.1 stated that cracking due to SCC could occur in the stainless steel piping, piping components, and piping elements of the BWR standby liquid control system that are exposed to sodium pentaborate solution greater than 60˚C (>140˚F). The existing aging management program relies on monitoring and control of water chemistry to manage the aging effects of cracking due to SCC. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause SCC. Therefore, the GALL Report recommends that the effectiveness of the water chemistry control program should be verified to ensure that SCC is not occurring. A one-time inspection of select components at susceptible locations is an acceptable method to ensure that SCC is not occurring and that the component's intended function will be maintained during the period of extended operation.

In the OCGS LRA Section 3.3.2.2.3.1, the applicant addressed cracking of stainless steel piping, piping components, and piping elements due to SCC in the BWR standby liquid control system. The OCGS LRA stated that Oyster Creek will implement a One-Time Inspection Program, B.1.24, for susceptible locations to verify the effectiveness of the Water Chemistry Program, B.1.2, to manage stress corrosion cracking of stainless steel components exposed to a sodium pentaborate environment in the standby liquid control system (liquid poison system). The management of stress corrosion cracking of standby liquid control system (liquid poison system) components exposed to sodium pentaborate relies on monitoring and control of liquid poison tank makeup water chemistry. The makeup water is monitored in lieu of the sodium pentaborate solution since the sodium pentaborate would mask most of the chemistry parameters monitored by the Water Chemistry Program. The effectiveness of this approach is verified by a one-time inspection of susceptible locations. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's Water Chemistry Program (AMP B.1.2) and verified that this aging management program include activities that will mitigate cracking due to SCC. In addition, the project team reviewed the applicant's One-Time Inspection Program (B.1.24) and verified that this aging management program includes inspections of the standby liquid control system to detect cracking due to SCC as a means of verifying the effectiveness of the Water Chemistry Program. The project team concurred with the applicant's approach to manage stress corrosion cracking of standby liquid control system (liquid poison system) components exposed to sodium pentaborate by relying on monitoring and control of liquid poison tank makeup water chemistry since the sodium pentaborate would mask most of the chemistry parameters monitored by the Water Chemistry Program. The project team determined that these AMPs will adequately manage cracking due to SCC for stainless steel piping, piping components, and piping elements in the BWR standby liquid control system.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.3.2.2.3.1 for further evaluation.

3.3.2.2.3.2 Cracking Due to Stress Corrosion Cracking [Item 2]

The project team reviewed OCGS LRA Section 3.3.2.2.3.2 against the criteria in SRP-LR Section 3.3.2.2.3.2.

SRP-LR Section 3.3.2.2.3.2 stated that cracking due to SCC could occur in stainless steel and stainless clad steel heat exchanger components exposed to treated water greater than 60˚C (>140˚F). The GALL Report recommends further evaluation of a plant-specific aging management program to ensure that these aging effects are adequately managed.

In the OCGS LRA Section 3.3.2.2.3.2, the applicant addressed cracking of stainless steel and stainless clad steel heat exchanger components due to SCC. The OCGS LRA stated that, at Oyster Creek, stainless steel components in closed cooling water systems are exposed to a closed cycle cooling water environment <140˚F and are not susceptible to cracking due to stress corrosion cracking. The reactor water cleanup (RWCU) system non-regenerative heat exchanger shell side components are carbon steel and are not susceptible to cracking due to stress corrosion cracking. Reactor water cleanup system regenerative heat exchanger stainless steel tube and shell side components, and non-regenerative heat exchanger stainless steel tube side components are exposed to a treated water environment >140˚F and are susceptible to cracking due to stress corrosion cracking. Oyster Creek will implement a One-Time Inspection Program, B.1.24, for susceptible locations to verify the effectiveness of the Water Chemistry

Program, B.1.2, to manage stress corrosion cracking of stainless steel RWCU heat exchanger components exposed to a treated water environment >140˚F. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's Water Chemistry Program (AMP B.1.2) and verified that this aging management program include activities that will mitigate cracking due to SCC. In addition, the project team reviewed the applicant's One-Time Inspection Program (B.1.24) and verified that this aging management program includes inspections of the reactor water cleanup system regenerative heat exchanger stainless steel tube and shell side components, and non-regenerative heat exchanger stainless steel tube side components to detect cracking due to SCC as a means of verifying the effectiveness of the Water Chemistry Program. The project team determined that these AMPs will adequately manage cracking due to SCC for stainless steel heat exchanger components in the reactor water cleanup system.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.3.2.2.3.2 for further evaluation.

3.3.2.2.3.3 Cracking Due to Stress Corrosion Cracking [Item 3]

The applicant addressed the further evaluation for cracking due to SCC of stainless steel diesel engine exhaust piping in LRA Section 3.3.2.2.3.2, in accordance with the draft January 2005 SRP-LR. Therefore, the project team reviewed OCGS LRA Section 3.3.2.2.3.2 against the criteria in SRP-LR Section 3.3.2.2.3.3.

SRP-LR Section 3.3.2.2.3.3 stated that cracking due to SCC could occur in stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust. The GALL Report recommended further evaluation of a plant-specific aging management program to ensure that these aging effects are adequately managed.

In the OCGS LRA, Section 3.3.2.2.3.2, the applicant addressed cracking of diesel engine exhaust piping due to SCC. The OCGS LRA stated that, for Oyster Creek, Table 3.3.1, item number 5 for stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust gases is not used. Emergency diesel generator components exposed to diesel exhaust gases are carbon steel and are not susceptible to cracking due to stress corrosion cracking.

The project team reviewed Table 3.3.2.2.1.13 in the OCGS LRA, which addresses aging management of the emergency diesel generator and auxiliary system, and confirmed that the diesel engine exhaust piping is identified as being constructed of carbon and low alloy steel; not stainless steel. Therefore, the project team concurred with the applicant's conclusion that this further evaluation is not applicable to Oyster Creek.

3.3.2.2.4 Cracking Due to Stress Corrosion Cracking and Cyclic Loading

3.3.2.2.4.1 Cracking Due to Stress Corrosion Cracking and Cyclic Loading [Item 1]

In Section 3.3.2.2.4.3 of the OCGS LRA, the applicant stated that cracking due to stress corrosion cracking and cyclic loading of stainless steel components exposed to treated borated water is applicable to PWRs only. The project team concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek is a BWR plant.

3.3.2.2.4.2 Cracking Due to Stress Corrosion Cracking and Cyclic Loading [Item 2]

In Section 3.3.2.2.4.3 of the OCGS LRA, the applicant stated that cracking due to stress corrosion cracking and cyclic loading of stainless steel components exposed to treated borated water is applicable to PWRs only. The project team concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek is a BWR plant.

3.3.2.2.4.3 Cracking Due to Stress Corrosion Cracking and Cyclic Loading [Item 3]

In Section 3.3.2.2.4.2 of the OCGS LRA, the applicant stated that cracking due to stress corrosion cracking and cyclic loading of stainless steel components in the PWR chemical and volume control system is applicable to PWRs only. The project team concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek is a BWR plant.

3.3.2.2.4.4 Cracking Due to Stress Corrosion Cracking and Cyclic Loading [Item 4]

The applicant addressed the further evaluation for cracking due to SCC and cyclic loading for high-strength steel closure bolting in Section 3.3.2.2.4.1 of the OCGS LRA, in accordance with the draft January 2005 SRP-LR. Therefore, the project team reviewed OCGS LRA Section 3.3.2.2.4.1 against the criteria in SRP-LR Section 3.3.2.2.4.4. The project team noted that Section 3.3.2.2.4.4 was inadvertently omitted from the September 2005 SRP-LR, Rev. 1, although it is referenced in Table 3.3-1, line item 10, of that document.

SRP-LR Section 3.3.2.2.4.4 stated that cracking due to SCC and cyclic loading could occur for high-strength steel closure bolting in auxiliary systems exposed to air with steam or water leakage. The GALL Report recommended the bolting integrity program be used to manage this aging effect, and that this AMP is to be augmented by appropriate inspection to detect cracking if the bolts are not otherwise replaced during maintenance.

In the OCGS LRA, Section 3.3.2.2.4.1, the applicant addressed cracking of high-strength steel closure bolting due to SCC and cyclic loading. The OCGS LRA stated that, at Oyster Creek the only auxiliary system that contains high-strength steel closure bolting exposed to air with steam or water leakage is the control rod drive system. The Bolting Integrity Program, B.1.12, addresses aging management requirements for this ASME Class 1 high-strength steel closure bolting. Bolting integrity management follows published EPRI guidelines and other industry recommendations for material selection and testing, inservice inspection (ISI), and plant surveillance and maintenance practices. The extent and schedule of the inspections for the Class 1 high-strength steel closure bolting in the control rod drive system is in accordance with ASME Section XI and assures that detection of leakage or fastener degradation will occur prior to loss of system or component intended function. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's Bolting Integrity Program (AMP B.1.12) and verified that this aging management program included activities that will manage cracking of high-strength steel closure bolting due to SCC and cyclic loading. This program includes inservice inspection of high-strength bolting as part of the ASME Section XI ISI requirements; therefore, the requirements for augmented inspection are met. The project team determined that this AMP will adequately manage cracking of high-strength steel closure bolting due to SCC and cyclic loading in the control rod drive system.

The project team found that, based on the program identified above, the applicant has met the criteria of SRP-LR Section 3.3.2.2.4.4 for further evaluation.

3.3.2.2.5 Hardening and Loss of Strength Due to Elastomer Degradation

3.3.2.2.5.1 Hardening and Loss of Strength Due to Elastomer Degradation [Item 1]

The project team reviewed OCGS LRA Section 3.3.2.2.5.1 against the criteria in SRP-LR Section 3.3.2.2.5.1.

SRP-LR Section 3.3.2.2.5.1 stated that hardening and loss of strength due to elastomer degradation could occur in elastomer seals and components of heating and ventilation systems exposed to air – indoor uncontrolled (internal/external). The GALL Report recommended further evaluation of a plant-specific aging management program to ensure that these aging effects are adequately managed.

In the OCGS LRA Section 3.3.2.2.5.1, the applicant addressed hardening and loss of strength of elastomer seals and components due to elastomer degradation. The OCGS LRA stated that Oyster Creek will implement a periodic inspection of ventilation systems program, B.2.4, for the internal and external inspection of elastomer components exposed to an indoor air internal or external environment in the ?C" battery room heating and ventilation system, 480V switchgear room ventilation system, battery and MG set room ventilation system, control room HVAC system, radwaste area heating and ventilation system, and reactor building ventilation system. Periodic inspections are performed on elastomer door seals and flexible connections to identify detrimental changes in material properties, as evidenced by cracking, perforations in the material, or leakage. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's further evaluation and determined that the periodic inspection of ventilation systems program (AMP B.2.4) is a plant specific program that is appropriate to inspect the internal and external inspection of elastomer components exposed to an indoor air internal or external environment. The technical evaluation of this program to determine its adequacy was performed by NRC DE staff, and is addressed in the SER related to the Oyster Creek plant.

Oyster Creek will implement a structures monitoring program, B.1.31, for the external inspections of expansion joint and flexible connection elastomers exposed to an indoor air external environment in the circulating water system, heating & process steam system, fire protection system, process sampling system, condensate system, and condensate transfer system. Oyster Creek utilizes the structures monitoring program to inspect the external surfaces of piping, piping components, and piping elements when there are no aging management programs that specifically inspect the component in question. The structures monitoring program relies on periodic visual inspections by qualified individuals to identify and evaluate the degradation of elastomer components to ensure that there is no loss of intended function. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's structures monitoring program (B.1.31) and verified that this aging management program included external inspections of expansion joint and flexible connection elastomers exposed to an indoor air external environment. The project team determined that these AMPs will adequately manage hardening and loss of strength of elastomer seals and components due to elastomer degradation in elastomer components in the aforementioned auxiliary systems in the circulating water system, heating & process steam system, fire protection system, process sampling system, condensate system, and condensate transfer system.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.3.2.2.5.1 for further evaluation.

3.3.2.2.5.2 Hardening and Loss of Strength Due to Elastomer Degradation [Item 2]

The project team reviewed OCGS LRA Section 3.3.2.2.5.2 against the criteria in SRP-LR Section 3.3.2.2.5.2.

SRP-LR Section 3.3.2.2.5.2 stated that hardening and loss of strength due to elastomer degradation could occur in elastomer linings of the filters, valves, and ion exchangers in spent fuel pool cooling and cleanup systems exposed to treated water. The GALL Report recommended that a plant-specific aging management program be evaluated to determine and assess the qualified life of the linings in the environment to ensure that these aging effects are adequately managed.

In the OCGS LRA Section 3.3.2.2.5.2, the applicant addressed hardening and loss of strength of elastomer linings of the filters, valves, and ion exchangers in spent fuel pool cooling and cleanup systems due to elastomer degradation. The OCGS LRA stated that Oyster Creek will implement a Periodic Inspection Program, B.2.5, for the internal inspection of expansion joint and flexible connection elastomers exposed to a treated water internal environment in the condensate system, condensate transfer system, heating & process steam system, and process sampling system. Oyster Creek utilizes the Periodic Inspection Program to periodically monitor component aging effects when the component is not covered by other existing periodic monitoring programs. The Periodic Inspection Program relies on periodic inspections to identify and evaluate the internal degradation of elastomer components exposed to a treated water internal environment to ensure that there is no loss of intended function. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's further evaluation and determined that the Periodic Inspection Program (AMP B.2.5) is a plant specific program that is appropriate to manage hardening and loss of strength of elastomer linings of the filters, valves, and ion exchangers in spent fuel pool cooling and cleanup systems due to elastomer degradation. The technical evaluation of this program to determine its adequacy was performed by NRC DE staff, and is addressed in the SER related to the Oyster Creek plant.

The project team found that, based on the program identified above, the applicant has met the criteria of SRP-LR Section 3.3.2.2.5.2 for further evaluation.

3.3.2.2.6 Reduction of Neutron-Absorbing Capacity and Loss of Material Due to General Corrosion

The applicant addressed reduction of neutron-absorbing capacity and loss of material due to general corrosion in the neutron absorbing sheets of the spent fuel storage racks in LRA Section 3.3.2.2.14, in accordance with the draft January 2005 SRP-LR. Therefore, the project team reviewed OCGS LRA Section 3.3.2.2.14 against the criteria in SRP-LR Section 3.3.2.2.6.

SRP-LR Section 3.3.2.2.6 stated that reduction of neutron-absorbing capacity and loss of material due to general corrosion could occur in the neutron-absorbing sheets of BWR spent fuel storage racks exposed to treated water. The GALL Report recommended further evaluation of a plant-specific aging management program to ensure that these aging effects are adequately managed.

In the OCGS LRA Section 3.3.2.2.14, the applicant addressed neutron-absorbing capacity and loss of material of the neutron-absorbing sheets of BWR spent fuel storage racks due to general corrosion. The OCGS LRA stated that, at Oyster Creek, the aging effects of the Boral spent fuel storage racks exposed to a treated water environment are insignificant and require no aging management. The potential aging effects resulting from sustained irradiation of Boral were previously evaluated by the staff (BNL-NUREG-25582, dated January 1979; NUREG-1787, VC Summer SER, paragraph 3.5.2.4.2) and determined to be insignificant. Oyster Creek installed four (4) spent fuel storage racks, manufactured by HOLTEC International, that utilized Boral neutron absorbing material, in the year 2000. The Boral coupons kept inside the spent fuel storage pool were removed and inspected in 2002, and again in 2004. Inspection results showed no blisters, pits, dimensional changes, or other age related degradations. Neutron transmission tests on the irradiated coupon showed that the average Boron-10 areal density in the irradiated coupon is 0.0209 grams/cm^2, which means that, within the experimental accuracy, no Boron-10 has been lost from the coupons. Plant operating experience is therefore consistent with the staff's previous conclusion, and an aging management program is not required.

The project team reviewed Holtec International Report No. HI-2043279, "Summary Report of the Examination of Oyster Creek Nuclear Station Boral Surveillance Coupon No. HO910070-2-6," 10/19/04, which concluded that the coupon tested showed no blisters, pits, or other degradation. Neutron transmission tests on the irradiated coupon showed the average Boron-10 areal density is 0.0209 grams/cm^2, which means that Boron-10 has not been lost from the coupon. In addition, the project team reviewed Holtec International Report No. HI-2033000, "Examination of Oyster Creek Nuclear Station Boral Surveillance Coupon No. HO920023-2-6," Revision 1, 04/08/03, which concluded that the coupon tested showed no blisters, pits, or other degradation. Neutron transmission tests on the irradiated coupon showed the average Boron-10 areal density is 0.0194 grams/cm2, which means Boron-10 has not been lost from the coupon. Based on these reports, the project team determined that the results of the Boral coupon tests support the applicant's conclusion that the aging effects of the Boral spent fuel storage racks exposed to a treated water environment are insignificant and require no aging management.

The project team found that, based on the information discussed above, the applicant has met the criteria of SRP-LR Section 3.3.2.2.6 for further evaluation.

3.3.2.2.7 <u>Loss of Material Due to General, Pitting, and Crevice Corrosion</u>

3.3.2.2.7.1 <u>Loss of Material Due to General, Pitting, and Crevice Corrosion [Item 1]</u>

The applicant addressed loss of material due to general, pitting, and crevice corrosion for components exposed to lubricating oil in OCGS LRA Sections 3.3.2.2.7.1 and 3.3.2.2.7.3, in accordance with the draft January 2005 SRP-LR. Therefore, the project team reviewed OCGS LRA Sections 3.3.2.2.7.1 and 3.3.2.2.7.3 against the criteria in SRP-LR Section 3.3.2.2.7.1.

SRP-LR Section 3.3.2.2.7.1 stated that loss of material due to general, pitting, and crevice corrosion could occur in steel piping, piping components, and piping elements, including the tubing, valves, and tanks in the reactor coolant pump oil collection system, exposed to lubricating oil (as part of the fire protection system). The existing aging management program relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. However, control of lube oil contaminants may not always have been adequate to preclude corrosion. Therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion is not occurring. The GALL Report recommended further evaluation of programs to manage corrosion to verify the effectiveness of the lubricating oil program. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In addition, the SRP-LR stated that corrosion may occur at locations in the reactor coolant pump oil collection tank where water from wash downs may accumulate. Therefore, the effectiveness of the program should be verified to ensure that corrosion is not occurring. The GALL Report recommended further evaluation of programs to manage loss of material due to general, pitting, and crevice corrosion, to include determining the thickness of the lower portion of the tank. A one-time inspection is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In the OCGS LRA Section 3.3.2.2.7.1, the applicant addressed loss of material of steel piping, piping components, and piping elements, including the tubing, valves, and tanks in the reactor coolant pump oil collection system due to general, pitting, and crevice corrosion . The OCGS LRA stated that Item numbers 3.3.1-13 and 3.3.1-14 (in Table 3.3.1) are not applicable to Oyster Creek. Appendix R Section III.O does not apply since the containment is inert during normal operation.

The project team recognized that the Oyster Creek containment is inert during normal operation, which effectively eliminates the possibility of a fire. Therefore, the requirements of Appendix R, Section III.O to have a reactor coolant pump oil collection system do not apply. The project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

In the OCGS LRA, Section 3.3.2.2.7.3, the applicant addressed loss of material for steel piping, piping components, piping elements, ducting, closure bolting and heat exchanger tubes exposed to lubricating oil due to general, pitting, and crevice corrosion. The applicant stated that Oyster Creek will implement a One-Time Inspection Program, B.1.24, for susceptible locations to verify the effectiveness of the lubricating oil monitoring activities program, B.2.2, to manage the loss of material in steel piping, piping components, and piping elements exposed to lubricating oil internal or external environments in the emergency diesel generator and auxiliary system, reactor recirculation system, reactor water cleanup system, reactor building closed cooling water system, control rod drive system, fire protection system, miscellaneous floor and equipment drain system, and service water system. The lubricating oil monitoring activities program manages physical and chemical properties of lubricating oil by sampling, testing, and trending to identify specific wear mechanisms, contamination, and oil degradation that could affect intended functions. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's further evaluation and determined that the lubricating oil monitoring activities program(AMP B.2.2) is a plant specific program that is appropriate to manage the loss of material in steel piping, piping components, and piping elements exposed to lubricating oil internal or external environments. The technical evaluation of this program to determine its adequacy was performed by NRC DE staff, and is addressed in the SER related to the Oyster Creek plant.

The project team found that, based on the information discussed above, the applicant has met the criteria of SRP-LR Section 3.3.2.2.7.1 for further evaluation.

3.3.2.2.7.2 Loss of Material Due to General, Pitting, and Crevice Corrosion [Item 2]

The project team reviewed OCGS LRA Section 3.3.2.2.7.2 against the criteria in SRP-LR Section 3.3.2.2.7.2.

SRP-LR Section 3.3.2.2.7.2 stated that loss of material due to general, pitting, and crevice corrosion could occur in steel piping, piping components, and piping elements in the BWR reactor water cleanup and shutdown cooling systems exposed to treated water. The existing aging management program relies on monitoring and control of reactor water chemistry to manage the aging effects of loss of material from general, pitting and crevice corrosion. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause general, pitting, or crevice corrosion. Therefore, the effectiveness of the chemistry control program should be verified to ensure that corrosion is not occurring. The GALL Report recommended further evaluation of programs to manage loss of material from general, pitting, and crevice corrosion to verify the effectiveness of the Water Chemistry Program. A one-time inspection of select components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In the OCGS LRA, Section 3.3.2.2.7.2, the applicant addressed loss of material of steel piping, piping components, and piping elements due to general, pitting, and crevice corrosion . The OCGS LRA stated that Oyster Creek will implement a One-Time Inspection Program, B.1.24, for susceptible locations to verify the effectiveness of the Water Chemistry Program, B.1.2, to manage the loss of material in steel and aluminum piping, piping components, and piping elements exposed to a treated water environment in the control rod drive system, post-accident sampling system, process sampling system, reactor head cooling system, reactor recirculation system, reactor water cleanup system, shutdown cooling system, spent fuel pool cooling system, standby liquid control system (liquid poison system), water treatment & distribution system, and in aluminum fuel pool gates and fuel storage and handling equipment and structures in the fuel storage and handling equipment system exposed to a treated water environment. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The OCGS LRA further stated that, when applied to steel ASME Class MC components in a treated water environment and to steel ASME Class 2 and 3 piping and components in a treated water environment, Oyster Creek will use ASME Section XI, Subsection IWF, B.1.28, to verify the effectiveness of the Water Chemistry Program, B.1.2, to mitigate loss of material. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's Water Chemistry Program (AMP B.1.2) and verified that this aging management program included activities that will mitigate loss of material due to general, pitting, and crevice corrosion. In addition, the project team reviewed the applicant's One-Time Inspection Program (B.1.24) and ASME Section XI, Subsection IWF program (AMP B.1.28), and verified that these AMPs included inspections to detect loss of material due to general, pitting, and crevice corrosion as a means of verifying the effectiveness of the Water Chemistry Program. The project team determined that these AMPs will adequately manage loss of material due to general, pitting, and crevice corrosion for steel piping, piping components, and piping elements in the control rod drive system, post-accident sampling system, process sampling system, reactor head cooling system, reactor recirculation system, reactor water cleanup system, shutdown cooling system, spent fuel pool cooling system, standby liquid control system (liquid poison system), water treatment & distribution system, and in aluminum fuel pool gates and fuel storage and handling equipment and structures in the fuel storage and handling equipment system.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.3.2.2.7.2 for further evaluation.

3.3.2.2.7.3 Loss of Material Due to General, Pitting, and Crevice Corrosion [Item 3]

The project team reviewed OCGS LRA Section 3.3.2.2.7.3 against the criteria in SRP-LR Section 3.3.2.2.7.3.

SRP-LR Section 3.3.2.2.7.3 stated that loss of material due to general (steel only) pitting and crevice corrosion could occur for steel and stainless steel diesel exhaust piping, piping components, and piping elements exposed to diesel exhaust. The GALL Report recommended further evaluation of a plant-specific aging management program to ensure that these aging effects are adequately managed.

In the OCGS LRA Section 3.3.2.2.7.3, the applicant addressed loss of material of steel and stainless steel diesel exhaust piping, piping components, and piping elements due to general (steel only) pitting and crevice corrosion. The OCGS LRA stated that Oyster Creek will implement a Periodic Inspection Program, B.2.5, to manage the loss of material in steel emergency diesel generator exhaust piping, piping components, and piping elements exposed to a diesel exhaust environment. The Periodic Inspection Program includes periodic condition monitoring examinations to assure that existing environmental conditions are not resulting in material degradation that could result in the loss of system intended functions. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant’s further evaluation and determined that the Periodic Inspection Program (AMP B.2.5) is a plant specific program that is appropriate to manage the loss of material in steel piping, piping components, and piping elements exposed to lubricating oil internal or external environments. The technical evaluation of this program to determine its adequacy was performed by NRC DE staff, and is addressed in the SER related to the Oyster Creek plant.

The project team found that, based on the program identified above, the applicant has met the criteria of SRP-LR Section 3.3.2.2.7.3 for further evaluation.

3.3.2.2.8 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion (MIC)

The applicant addressed loss of material due to general, pitting, crevice corrosion, and MIC for steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil in Section 3.3.2.2.8.1 of the OCGS LRA, in accordance with the draft January 2005

SRP-LR. Therefore, the project team reviewed OCGS LRA Section 3.3.2.2.8.1 against the criteria in SRP-LR Section 3.3.2.2.8.

SRP-LR Section 3.3.2.2.8 stated that loss of material due to general, pitting, crevice corrosion, and MIC could occur for steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil. The buried piping and tanks inspection program relies on industry practice, frequency of pipe excavation, and operating experience to manage the effects of loss of material from general, pitting, and crevice corrosion and MIC. The effectiveness of the buried piping and tanks inspection program should be verified to evaluate an applicant's inspection frequency and operating experience with buried components, ensuring that loss of material is not occurring.

In the OCGS LRA Section 3.3.2.2.8.1, the applicant addressed loss of material of steel piping, piping components, and piping elements due to general, pitting, crevice corrosion, and MIC. The OCGS LRA stated that Oyster Creek will implement a Buried Piping Inspection Program, B.1.26, to manage the loss of material in steel piping, piping components, and piping elements exposed to soil in the service water system, emergency service water system, fire protection system, drywell floor and equipment drain system, miscellaneous floor and equipment drain system, spent fuel pool cooling system, reactor building closed cooling water system, and roof drains and overboard discharge system. The Buried Piping Inspection Program includes preventive measures to mitigate corrosion and periodic inspection to manage the effects of corrosion on the pressure-retaining capacity of buried steel piping, piping components, and piping elements. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's Buried Piping Inspection Program (AMP B.1.26) and verified that this aging management program included inspections to detect loss of material of steel piping, piping components, and piping elements due to general, pitting, crevice corrosion, and MIC. See Section 3.0.3.2.21 of this audit report for team's AMP B.1.26 review.

The applicant was asked to confirm that, for each of the material/environment combinations for which the Buried Piping Inspection Program will be credited, at least one inspection (opportunistic or focused) has been, or will be performed prior to entering the extended period of operation, in addition to a focused inspection within the 10-year period after entering the extended period of operation. In response, the applicant stated the following:

> a) Carbon steel/soil – ECR 05-00344 is scheduled to replace underground carbon steel service water piping in [refueling outage] 1R21 (2006). During this replacement the service water piping will be excavated and inspections of the external coating of the carbon steel service water piping will be conducted.
>
> b) Cast iron/soil – Buried cast iron components in the scope of license renewal are valves and fire hydrants in the fire protection system. These buried components are coated with coal tar and epoxy coating in the same fashion as the buried carbon steel piping. A buried cast iron fire hydrant was replaced in 2003. The hydrant that was removed was found to have seat degradation and plugged drain holes, but there were no identified indications of external surface or coating degradation.
>
> c) Stainless steel / soil – The stainless steel piping in the scope of this program is potentially used in the heating and process steam system. This system is in scope for 10 CFR 54.4(a)(2) spatial interaction only. Normally, buried pipe is not in scope for (a)(2)

spatial interaction because leakage from a buried portion of pipe cannot spray onto safety-related components. However, this "buried" heating & process steam piping in scope is located in the pipe vault. The pipe vault is primarily an outdoor air environment, but is conservatively considered buried because it can accumulate debris. The Buried Piping Inspection Program includes an enhancement to inspect the piping inside this vault in conjunction with the preventative maintenance activity to inspect the vault, and pump out accumulated water every 6 months. This activity will be performed within the 10-year period immediately prior to entering the license renewal period. See Section 3.3 of program basis document PBD-AMP-B.1.26, Buried Piping Inspection.

d) Bronze/soil – The buried bronze components in the scope of this program are threaded fittings < 2.5 inches, potentially used in the roof drains and overboard discharge system. These buried fittings are coated with coal tar and epoxy coating in the same fashion as the buried carbon steel piping. These fittings are associated with an unpressurized drain system whose function is to drain water in the event of a fire protection water system initiation. As such, the pressure boundary integrity is not critical so long as the fitting does not become blocked such that drainage is prevented. These fittings will not be specifically identified for excavation and inspection, as they are adequately addressed by the inspections that have been or will be performed for the buried carbon steel piping external coating inspection.

e) Aluminum/soil – AR A2116126 is scheduled to inspect the coatings on two underground aluminum condensate transfer lines in 2006.

Upon entering the period of extended operation, focused inspection of buried piping and components will be performed within ten years, unless an opportunistic inspection occurs within this ten-year period. The inspections will include at least one carbon steel, one aluminum, and one cast iron pipe or component. In addition, for each of these materials, the locations selected for inspection will include at least one location where the pipe or component has not been previously replaced or re-coated, if any such locations remain. The stainless steel piping in the vault will continue to be periodically inspected, and the bronze material is addressed by the buried carbon steel pipe coating inspections, as described above.

The project team reviewed the applicant’s response and determined that, for each of the material/environment combinations for which the Buried Piping Inspection Program will be credited, at least one inspection (opportunistic or focused) has been, or will be performed prior to entering the extended period of operation, in addition to a focused inspection within the 10-year period after entering the extended period of operation that would provide objective evidence that the component coatings were in acceptable condition and that no significant aging was present for these buried components. On this basis, the project team determined that the applicant’s response was acceptable.

The project team determined that the Buried Piping Inspection AMP will adequately manage loss of material in steel piping, piping components, and piping elements exposed to soil in the service water system, emergency service water system, fire protection system, drywell floor and equipment drain system, miscellaneous floor and equipment drain system, spent fuel pool cooling system, reactor building closed cooling water system, and roof drains and overboard discharge system, and loss of material from the bottom of outdoor steel tanks supported by earthen foundations in the fire protection system

The OCGS LRA further stated that Oyster Creek will implement an aboveground outdoor tanks program, B.1.21, to manage the loss of material from the bottom of outdoor steel tanks supported by earthen foundations in the fire protection system. The aboveground outdoor tanks program provides for periodic internal UT inspections on the bottom of aboveground outdoor steel tanks supported by earthen foundations. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process. Oyster Creek does not have any buried tanks within the scope of License Renewal.

The project team reviewed the applicant's aboveground outdoor tanks program (AMP B.1.21) and verified that this aging management program included inspections to manage the loss of material from the bottom of outdoor steel tanks supported by earthen foundations in the fire protection system. The project team determined that this AMP will adequately manage loss of material from the bottom of outdoor steel tanks supported by earthen foundations in the fire protection system

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.3.2.2.8 for further evaluation.

3.3.2.2.9 <u>Loss of Material Due to General, Pitting, Crevice, Microbiologically Influenced Corrosion and Fouling</u>

3.3.2.2.9.1 <u>Loss of Material Due to General, Pitting, Crevice, Microbiologically Influenced Corrosion and Fouling [Item1]</u>

The project team reviewed OCGS LRA Section 3.3.2.2.9.1 against the criteria in SRP-LR Section 3.3.2.2.9.1.

SRP-LR Section 3.3.2.2.9.1 stated that loss of material due to general, pitting, crevice, MIC, and fouling could occur for steel piping, piping components, piping elements, and tanks exposed to fuel oil. The existing aging management program relies on the fuel oil chemistry program for monitoring and control of fuel oil contamination to manage loss of material due to corrosion or fouling. Corrosion or fouling may occur at locations where contaminants accumulate. The effectiveness of the fuel oil chemistry control should be verified to ensure that corrosion is not occurring. The GALL Report recommended further evaluation of programs to manage loss of material due to general, pitting, crevice, MIC, and fouling to verify the effectiveness of the fuel oil chemistry program. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In the OCGS LRA Section 3.3.2.2.9.1, the applicant addressed loss of material of steel piping, piping components, piping elements, and tanks due to general, pitting, crevice, MIC, and fouling. The OCGS LRA stated that Oyster Creek will implement a One-Time Inspection Program, B.1.24, for susceptible locations to verify the effectiveness of the fuel oil chemistry program, B.1.22, to manage the loss of material in steel piping, piping components, and piping elements exposed to a fuel oil internal environment in the emergency diesel generator and auxiliary system, main fuel oil storage & transfer system, and fire protection system. The verification of the fuel oil chemistry program to manage the loss of material in steel fuel oil tanks is implemented through the fuel oil chemistry program tank inspection activities which requires that fuel oil tanks be periodically drained, cleaned, and internally inspected to ensure that corrosion is not occurring and that there is no loss of intended function. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's fuel oil chemistry program (AMP B.1.24) and verified that this aging management program included activities that will mitigate loss of material due to general, pitting, crevice, MIC, and fouling. In addition, the project team reviewed the applicant's One-Time Inspection Program (B.1.24) and verified that this aging management program included inspections to detect loss of material due to general, pitting, crevice, MIC, and fouling as a means of verifying the effectiveness of the fuel oil chemistry program. The project team determined that these AMPs will adequately manage loss of material due to general, pitting, crevice, MIC, and fouling for steel piping, piping components, piping elements, and tanks exposed to fuel oil in the emergency diesel generator and auxiliary system, main fuel oil storage & transfer system, and fire protection system.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.3.2.2.9.1 for further evaluation.

3.3.2.2.9.2 Loss of Material Due to General, Pitting, Crevice, Microbiologically Influenced Corrosion and Fouling [Item 2]

The project team reviewed OCGS LRA Section 3.3.2.2.9.2 against the criteria in SRP-LR Section 3.3.2.2.9.2.

SRP-LR Section 3.3.2.2.9.2 stated that loss of material due to general, pitting, crevice, MIC, and fouling could occur for steel heat exchanger components exposed to lubricating oil. The existing aging management program relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. However, control of lube oil contaminants may not always have been adequate to preclude corrosion. Therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion is not occurring. The GALL Report recommended further evaluation of programs to manage corrosion to verify the effectiveness of the lube oil program. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In the OCGS LRA, Section 3.3.2.2.9.2, the applicant addressed loss of material of steel heat exchanger components due to general, pitting, crevice, MIC, and fouling. The OCGS LRA stated that Oyster Creek will implement a One-Time Inspection Program, B.1.24, for susceptible locations to verify the effectiveness of the lubricating oil monitoring activities program, B.2.2, to manage the loss of material in steel heat exchanger shell side components exposed to lubricating oil in the emergency diesel generator and auxiliary system, reactor water cleanup system, and reactor recirculation system. The lubricating oil monitoring activities program manages physical and chemical properties of lubricating oil by sampling, testing, and trending to identify specific wear mechanisms, contamination, and oil degradation that could affect intended functions. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's further evaluation and determined that the lubricating oil monitoring activities program (AMP B.2.2) is a plant specific program that is appropriate to manage the loss of material in steel heat exchanger shell side components exposed to lubricating oil. The technical evaluation of this program to determine its adequacy was performed by NRC DE staff, and is addressed in the SER related to the Oyster Creek plant.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.3.2.2.9.2 for further evaluation.

3.3.2.2.10 Loss of Material Due to Pitting and Crevice Corrosion

3.3.2.2.10.1 Loss of Material Due to Pitting and Crevice Corrosion in Steel with Elastomer Lining or Stainless Steel Cladding Exposed to Treated Water [Item 1]

The project team reviewed OCGS LRA Section 3.3.2.2.10.1 against the criteria in SRP-LR Section 3.3.2.2.10.1.

SRP-LR Section 3.3.2.2.10.1 stated that loss of material due to pitting and crevice corrosion could occur in BWR steel piping with elastomer lining or stainless steel cladding that are exposed to treated water if the cladding or lining is degraded. The existing aging management program relies on monitoring and control of reactor water chemistry to manage the aging effects of loss of material from pitting and crevice corrosion. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause pitting, or crevice corrosion. Therefore, the effectiveness of the chemistry control program should be verified to ensure that corrosion is not occurring. The GALL Report recommended further evaluation of programs to manage loss of material from pitting and crevice corrosion to verify the effectiveness of the Water Chemistry Program. A one-time inspection of select components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In the OCGS LRA Section 3.3.2.2.10.1, the applicant addressed loss of material of steel piping with elastomer lining or stainless steel cladding due to pitting and crevice corrosion. The OCGS LRA stated that Oyster Creek will implement a One-Time Inspection Program, B.1.24, for susceptible locations to verify the effectiveness of the Water Chemistry Program, B.1.2, to manage the loss of material in stainless steel or elastomer lined steel piping, piping components, piping elements, and heat exchanger tube side components exposed to a treated water environment in the control rod drive system, post-accident sampling system, process sampling system, reactor building closed cooling water system, reactor water cleanup system, shutdown cooling system, spent fuel pool cooling system, standby liquid control system (liquid poison system), water treatment & distribution system, reactor head cooling system, and in the primary containment. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

Oyster Creek will implement a One-Time Inspection Program, B.1.24, for susceptible locations to verify the effectiveness of the Water Chemistry Program, B.1.2, to manage the loss of material in stainless steel fuel storage and handling equipment and structures exposed to a treated water environment in the fuel storage and handling equipment system, and, to manage the loss of material in the stainless steel fuel pool skimmer surge tank liner exposed to a treated water environment in the reactor building structure. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

When applied to stainless steel ASME Class MC components in a treated water environment and to stainless steel ASME Class 2 and 3 piping and components in a treated water environment, Oyster Creek will use ASME Section XI, Subsection IWF, B.1.28, to verify the effectiveness of the Water Chemistry Program, B.1.2, to mitigate loss of material. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's Water Chemistry Program (AMP B.1.2) and verified that this aging management program included activities that will manage loss of material due to pitting and crevice corrosion. In addition, the project team reviewed the applicant's One-Time Inspection Program (B.1.24) and ASME Section XI, Subsection IWF (AMP B.1.28), and verified that these AMPs included inspections to detect loss of material due to pitting and crevice corrosion as a means of verifying the effectiveness of the Water Chemistry Program. The project team determined that these AMPs will adequately manage loss of material due to pitting and crevice corrosion for the aforementioned auxiliary systems.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.3.2.2.10.1 for further evaluation.

3.3.2.2.10.2 <u>Loss of Material Due to Pitting and Crevice Corrosion Stainless Steel Exposed to Treated Water [Item 2]</u>

The applicant addressed loss of material due to pitting and crevice corrosion of stainless steel and aluminum piping, piping components, piping elements, and for stainless steel and steel with stainless steel cladding heat exchanger components exposed to treated water in Sections 3.3.2.2.10.1 and 3.3.2.2.7.2 of the OCGS LRA, in accordance with the draft January 2005 SRP-LR. Therefore, the project team reviewed OCGS LRA Sections 3.3.2.2.10.1 and 3.3.2.2.7.2 against the criteria in SRP-LR Section 3.3.2.2.10.2.

SRP-LR Section 3.3.2.2.10.2 stated that loss of material due to pitting and crevice corrosion could occur for stainless steel and aluminum piping, piping components, piping elements, and for stainless steel and steel with stainless steel cladding heat exchanger components exposed to treated water. The existing aging management program relies on monitoring and control of reactor water chemistry to manage the aging effects of loss of material from pitting and crevice corrosion. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause pitting, or crevice corrosion. Therefore, the effectiveness of the chemistry control program should be verified to ensure that corrosion is not occurring. The GALL Report recommended further evaluation of programs to manage loss of material from pitting and crevice corrosion to verify the effectiveness of the Water Chemistry Program. A one-time inspection of select components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In the OCGS LRA Section 3.3.2.2.10.1, the applicant addressed loss of material of steel piping with elastomer lining or stainless steel cladding due to pitting and crevice corrosion. The OCGS LRA stated that Oyster Creek will implement a One-Time Inspection Program, B.1.24, for susceptible locations to verify the effectiveness of the Water Chemistry Program, B.1.2, to manage the loss of material in stainless steel or elastomer lined steel piping, piping components, piping elements, and heat exchanger tube side components exposed to a treated water environment in the control rod drive system, post-accident sampling system, process sampling system, reactor building closed cooling water system, reactor water cleanup system, shutdown cooling system, spent fuel pool cooling system, standby liquid control system (liquid poison system), water treatment & distribution system, reactor head cooling system, and in the primary containment. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

Oyster Creek will implement a One-Time Inspection Program, B.1.24, for susceptible locations to verify the effectiveness of the Water Chemistry Program, B.1.2, to manage the loss of material in stainless steel fuel storage and handling equipment and structures exposed to a treated water environment in the fuel storage and handling equipment system, and, to manage the loss of material in the stainless steel fuel pool skimmer surge tank liner exposed to a treated water environment in the reactor building structure. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

When applied to stainless steel ASME Class MC components in a treated water environment and to stainless steel ASME Class 2 and 3 piping and components in a treated water environment, Oyster Creek will use ASME Section XI, Subsection IWF, B.1.28, to verify the effectiveness of the Water Chemistry Program, B.1.2, to mitigate loss of material. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's Water Chemistry Program (AMP B.1.2) and verified that this aging management program included activities that will manage loss of material due to pitting and crevice corrosion. In addition, the project team reviewed the applicant's One-Time Inspection Program (B.1.24) and ASME Section XI, Subsection IWF (AMP B.1.28), and verified that these AMPs included inspections to detect loss of material due to pitting and crevice corrosion as a means of verifying the effectiveness of the Water Chemistry Program. The project team determined that these AMPs will adequately manage loss of material due to pitting and crevice corrosion for the fuel storage and handling equipment system, for the stainless steel fuel pool skimmer surge tank liner, and for the stainless steel ASME Class MC and Class 2 and 3 piping and components exposed to a treated water environment.

In the OCGS LRA, Section 3.3.2.2.7.2, the applicant addressed loss of material of steel piping, piping components, and piping elements due to general, pitting, and crevice corrosion . The OCGS LRA stated that Oyster Creek will implement a One-Time Inspection Program, B.1.24, for susceptible locations to verify the effectiveness of the Water Chemistry Program, B.1.2, to manage the loss of material in steel and aluminum piping, piping components, and piping elements exposed to a treated water environment in the control rod drive system, post-accident sampling system, process sampling system, reactor head cooling system, reactor recirculation system, reactor water cleanup system, shutdown cooling system, spent fuel pool cooling system, standby liquid control system (liquid poison system), water treatment & distribution system, and in aluminum fuel pool gates and fuel storage and handling equipment and structures in the fuel storage and handling equipment system exposed to a treated water environment. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The OCGS LRA further stated that, when applied to steel ASME Class MC components in a treated water environment and to steel ASME Class 2 and 3 piping and components in a treated water environment, Oyster Creek will use ASME Section XI, Subsection IWF, B.1.28, to verify the effectiveness of the Water Chemistry Program, B.1.2, to mitigate loss of material. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's Water Chemistry Program (AMP B.1.2) and verified that this aging management program included activities that will mitigate loss of material due to general, pitting, and crevice corrosion. In addition, the project team reviewed the applicant's One-Time Inspection Program (B.1.24) and ASME Section XI, Subsection IWF program (AMP B.1.28), and verified that these AMPs included inspections to detect loss of material due to general, pitting, and crevice corrosion as a means of verifying the effectiveness of the Water Chemistry Program. The project team determined that these AMPs will adequately manage loss of material due to general, pitting, and crevice corrosion for steel piping, piping components, and piping elements in the control rod drive system, post-accident sampling system, process sampling system, reactor head cooling system, reactor recirculation system, reactor water cleanup system, shutdown cooling system, spent fuel pool cooling system, standby liquid control system (liquid poison system), water treatment & distribution system, and in aluminum fuel pool gates and fuel storage and handling equipment and structures in the fuel storage and handling equipment system.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.3.2.2.10.2 for further evaluation.

3.3.2.2.10.3 Loss of Material Due to Pitting and Crevice Corrosion for Copper Alloy Exposed to External Condensation [Item 3]

The applicant addressed loss of material due to pitting and crevice corrosion of copper alloy HVAC piping, piping components, and piping elements exposed to condensation (external) in Section 3.3.2.2.10.2 of the OCGS LRA, in accordance with the draft January 2005 SRP-LR. Therefore, the project team reviewed OCGS LRA Section 3.3.2.2.10.2 against the criteria in SRP-LR Section 3.3.2.2.10.3.

SRP-LR Section 3.3.2.2.10.3 stated that loss of material due to pitting and crevice corrosion could occur for copper alloy HVAC piping, piping components, and piping elements exposed to condensation (external). The GALL Report recommended further evaluation of a plant-specific aging management program to ensure that these aging effects are adequately managed.

In the OCGS LRA Section 3.3.2.2.10.2, the applicant addressed loss of material of copper alloy HVAC piping, piping components, and piping elements due to pitting and crevice corrosion. The OCGS LRA stated that Oyster Creek will implement a One-Time Inspection Program, B.1.24, for susceptible locations to verify the effectiveness of the Water Chemistry Program, B.1.2, to manage the loss of material in stainless steel and copper alloy piping, piping components, and piping elements exposed to a treated water internal or external environment in the heating & process steam system, reactor water cleanup system, noble metals monitoring system, and control rod drive system. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's Water Chemistry Program (AMP B.1.2) and verified that this aging management program included activities that will manage loss of material due to pitting and crevice corrosion. In addition, the project team reviewed the applicant's One-Time Inspection Program (B.1.24), and verified that this aging management program included inspections to detect loss of material due to pitting and crevice corrosion as a means of verifying the effectiveness of the Water Chemistry Program. The project team determined that these AMPs will adequately manage loss of material due to pitting and crevice corrosion for the heating & process steam system, reactor water cleanup system, noble metals monitoring system, and control rod drive system.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.3.2.2.10.3 for further evaluation.

3.3.2.2.10.4 Loss of Material Due to Pitting and Crevice Corrosion for Copper Alloy Exposed to Lubricating Oil [Item 4]

The applicant addressed loss of material due to pitting and crevice corrosion for copper alloy piping, piping components, and piping elements exposed to lubricating oil in Section 3.3.2.2.11 of the OCGS LRA, in accordance with the draft January 2005 SRP-LR. Therefore, the project team reviewed OCGS LRA Section 3.3.2.2.11 against the criteria in SRP-LR Section 3.3.2.2.10.4.

SRP-LR Section 3.3.2.2.10.4 stated that loss of material due to pitting and crevice corrosion could occur for copper alloy piping, piping components, and piping elements exposed to lubricating oil. The existing aging management program relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. However, control of lube oil contaminants may not always have been adequate to preclude corrosion. Therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion is not occurring. The GALL Report recommended further evaluation of programs to manage corrosion to verify the effectiveness of the lubricating oil program. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In the OCGS LRA Section 3.3.2.2.11, the applicant addressed loss of material of copper alloy piping, piping components, and piping elements exposed to lubricating oil due to pitting and crevice corrosion. The OCGS LRA stated that Oyster Creek will implement a One-Time Inspection Program, B.1.24, for susceptible locations to verify the effectiveness of the lubricating oil monitoring activities program, B.2.2, to manage the loss of material in copper alloy piping, piping components, piping elements, and heat exchangers exposed to a lubricating oil environment in the service water system, reactor water cleanup system, emergency diesel generator and auxiliary system, and fire protection system. The lubricating oil monitoring activities program manages physical and chemical properties of lubricating oil by sampling, testing, and trending to identify specific wear mechanisms, contamination, and oil degradation that could affect intended functions. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's further evaluation and determined that the lubricating oil monitoring activities program (AMP B.2.2) is a plant specific program that is appropriate to manage the loss of material in copper alloy piping, piping components, piping elements, and heat exchangers exposed to a lubricating oil environment. The technical evaluation of this program to determine its adequacy was performed by NRC DE staff, and is addressed in the SER related to the Oyster Creek plant.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.3.2.2.10.4 for further evaluation.

3.3.2.2.10.5 Loss of Material Due to Pitting and Crevice Corrosion for Stainless Steel Exposed to Condensation [Item 5]

The applicant addressed loss of material due to pitting and crevice corrosion for stainless steel ducting and components exposed to condensation in Section 3.3.2.2.10.2 of the OCGS LRA, in accordance with the draft January 2005 SRP-LR. Therefore, the project team reviewed OCGS LRA Section 3.3.2.2.10.2 against the criteria in SRP-LR Section 3.3.2.2.10.5.

SRP-LR Section 3.3.2.2.10.5 stated that loss of material due to pitting and crevice corrosion could occur for HVAC aluminum piping, piping components, and piping elements, and stainless steel ducting and components exposed to condensation. The GALL Report recommended further evaluation of a plant-specific aging management program to ensure that these aging effects are adequately managed.

In the OCGS LRA, Section 3.3.2.2.10.2, the applicant addressed loss of material of stainless steel ducting, due to pitting and crevice corrosion. The OCGS LRA stated that Oyster Creek will implement a One-Time Inspection Program, B.1.24, to manage the loss of material in stainless steel piping, piping components, and piping elements exposed to a condensation internal environment in the hydrogen & oxygen monitoring system, and nitrogen supply system. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's one-time inspection aging management program (AMP B.1.24), and determined that it includes activities that are adequate to manage loss of material of stainless steel components exposed to condensation. The project team determined that the applicant appropriately addressed loss of material in stainless steel piping, piping components, and piping elements exposed to a condensation internal environment in the hydrogen & oxygen monitoring system, and nitrogen supply system

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.3.2.2.10.5 for further evaluation.

3.3.2.2.10.6 Loss of Material Due to Pitting and Crevice Corrosion for Copper Alloy Exposed to Internal Condensation [Item 6]

The project team noted that the applicant did not credit the GALL Report AMR for loss of material due to pitting and crevice corrosion for copper alloy fire protection piping, piping components, and piping elements exposed to condensation (internal), which is associated with this further evaluation, for the Oyster Creek auxiliary systems. This was a new AMR that was not in the draft January 2005 GALL Report.

The project team reviewed Tables 3.3.2.1.1 through 3.3.2.1.41 in the OCGS LRA for the auxiliary systems and noted that other GALL AMR line items that address same material/environment combinations were appropriately credited. Therefore, the project team determined that this further evaluation is not applicable to Oyster Creek.

3.3.2.2.10.7 Loss of Material Due to Pitting and Crevice Corrosion for Stainless Steel Exposed to Soil [Item 7]

The project team noted that the applicant did not credit the GALL Report AMR for loss of material due to pitting and crevice corrosion for stainless steel piping, piping components, and piping elements exposed to soil, which is associated with this further evaluation, for the Oyster Creek auxiliary systems. This was a new AMR that was not in the draft January 2005 GALL Report.

The project team reviewed Tables 3.3.2.1.1 through 3.3.2.1.41 in the OCGS LRA for the auxiliary systems and noted that other GALL AMR line items that address same material/environment combinations were appropriately credited. Therefore, the project team determined that this further evaluation is not applicable to Oyster Creek.

3.3.2.2.10.8 Loss of Material Due to Pitting and Crevice Corrosion for Stainless Steel Exposed to Sodium Pentaborate Solution [Item 8]

The applicant addressed loss of material due to pitting and crevice corrosion for stainless steel piping, piping components, and piping elements of the BWR standby liquid control system that are exposed to sodium pentaborate solution in Section 3.3.2.2.10.1 of the OCGS LRA, in accordance with the draft January 2005 SRP-LR. Therefore, The project team reviewed OCGS LRA Section 3.3.2.2.10.1 against the criteria in SRP-LR Section 3.3.2.2.10.8.

SRP-LR Section 3.3.2.2.10.8 stated that loss of material due to pitting and crevice corrosion could occur for stainless steel piping, piping components, and piping elements of the BWR standby liquid control system that are exposed to sodium pentaborate solution. The existing aging management program relies on monitoring and control of water chemistry to manage the aging effects of loss of material due to pitting and crevice corrosion. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause loss of material due to pitting and crevice corrosion. Therefore, the GALL Report recommended that the effectiveness of the water chemistry control program should be verified to ensure this aging is not occurring. A one-time inspection of select components at susceptible locations is an acceptable method to ensure that loss of material due to pitting and crevice corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In the OCGS LRA Section 3.3.2.2.10.1, the applicant addressed loss of material of steel piping with elastomer lining or stainless steel cladding due to pitting and crevice corrosion. The OCGS LRA stated that Oyster Creek will implement a One-Time Inspection Program, B.1.24, for susceptible locations to verify the effectiveness of the Water Chemistry Program, B.1.2, to manage the loss of material in stainless steel or elastomer lined steel piping, piping components, piping elements, and heat exchanger tube side components exposed to a treated water environment in the control rod drive system, post-accident sampling system, process sampling system, reactor building closed cooling water system, reactor water cleanup system, shutdown cooling system, spent fuel pool cooling system, standby liquid control system (liquid poison system), water treatment & distribution system, reactor head cooling system, and in the primary containment. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's Water Chemistry Program (AMP B.1.2) and verified that this aging management program include activities that will manage loss of material of steel piping in the standby liquid control system due to pitting and crevice corrosion. In addition, the project team reviewed the applicant's One-Time Inspection Program (B.1.24) and verified that this aging management program includes inspections of the standby liquid control system to detect loss of material as a means of verifying the effectiveness of the Water Chemistry Program. The project team determined that these AMPs will adequately manage loss of material due to pitting and crevice corrosion for stainless steel piping, piping components, and piping elements in the BWR standby liquid control system.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.3.2.2.10.8 for further evaluation.

3.3.2.2.11 Loss of Material Due to Pitting, Crevice, and Galvanic Corrosion for Copper Alloy Exposed to Treated Water

The applicant addressed loss of material due to pitting, crevice, and galvanic corrosion for copper alloy piping, piping components, and piping elements exposed to treated water in Attachment 3, Item AP-64 of its reconciliation of the AMPs in the draft January 2005 GALL Report to the approved September 2005 GALL Report. The project team reviewed the applicant's evaluation against the criteria in SRP-LR Section 3.3.2.2.11.

SRP-LR Section 3.3.2.2.11 stated that loss of material due to pitting, crevice, and galvanic corrosion could occur for copper alloy piping, piping components, and piping elements exposed to treated water. Therefore, the GALL Report recommended that the effectiveness of the water chemistry control program should be verified to ensure this aging is not occurring. A one-time inspection of select components at susceptible locations is an acceptable method to ensure that loss of material due to pitting and crevice corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In Attachment 3, Item AP-64 of its reconciliation document, the applicant addressed loss of material of copper alloy piping, piping components, and piping elements exposed to treated water due to pitting, crevice, and galvanic corrosion. The applicant stated that the AMR line item for copper alloy piping elements in treated water, addressing loss of material due to corrosion, recommended the Closed-Cycle Cooling Water System program with no further evaluation required in January 2005, and has been changed in September 2005 to recommend the water chemistry and one-time inspection, with further evaluation of detected aging effects. There are 4 instances of this line item being used in the condensate transfer and reactor building closed cooling water systems. In the Oyster Creek LRA, these 4 instances already specify the water chemistry and one-time inspection programs (with a standard 'E' note stating that a different aging management program than was specified in January 2005 GALL was credited). Therefore, the Oyster Creek LRA implements the One-Time Inspection Program and is consistent with GALL. Since observed conditions that have the potential for impacting an Intended function are evaluated or corrected in accordance with the corrective action process, there is high confidence that the aging effect will be adequately managed.

The project team reviewed the applicant's Water Chemistry Program (AMP B.1.2) and verified that this aging management program include activities that will manage loss of material of copper alloy piping, piping components, and piping elements exposed to treated water due to pitting, crevice, and galvanic corrosion. In addition, the project team reviewed the applicant's One-Time Inspection Program (B.1.24) and verified that this aging management program includes inspections to detect loss of material as a means of verifying the effectiveness of the Water Chemistry Program. The project team determined that these AMPs will adequately manage loss of material for copper alloy piping, piping components, and piping elements exposed to treated water due to pitting, crevice, and galvanic corrosion in the condensate transfer and reactor building closed cooling water systems.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.3.2.2.11 for further evaluation.

3.3.2.2.12 Loss of Material Due to Pitting, Crevice, and Microbiologically Influenced Corrosion

3.3.2.2.12.1 Loss of Material Due to Pitting, Crevice, and Microbiologically Influenced Corrosion for Aluminum, Copper Alloy and Stainless Steel Exposed to Fuel Oil [Item 1]

The applicant addressed loss of material due to pitting, crevice, and microbiologically influenced corrosion for aluminum and copper alloy piping, piping components, and piping elements exposed to fuel oil in Section 3.3.2.2.12.1 of the OCGS LRA, and stainless steel piping, piping components, and piping elements exposed to fuel oil in Attachment 3, Item AP-54 of its reconciliation of the AMPs in the draft January 2005 GALL Report to the approved September 2005 GALL Report. The project team reviewed the applicant's further evaluations against the criteria in SRP-LR Section 3.3.2.2.12.1.

SRP-LR Section 3.3.2.2.12.1 stated that loss of material due to pitting, crevice, and MIC could occur in stainless steel, aluminum, and copper alloy piping, piping components, and piping elements exposed to fuel oil. The existing aging management program relies on the fuel oil chemistry program for monitoring and control of fuel oil contamination to manage loss of material due to corrosion. However, corrosion may occur at locations where contaminants accumulate and the effectiveness of fuel oil chemistry control should be verified to ensure that corrosion is not occurring. The GALL Report recommended further evaluation of programs to manage corrosion to verify the effectiveness of the fuel oil chemistry control program. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In the OCGS LRA Section 3.3.2.2.12.1, the applicant addressed loss of material of aluminum and copper alloy piping, piping components, and piping elements exposed to fuel oil due to pitting, crevice, and MIC. The OCGS LRA stated that Oyster Creek will implement a One-Time Inspection Program, B.1.24, for susceptible locations to verify the effectiveness of the fuel oil chemistry program, B.1.22, to manage the loss of material in aluminum and copper alloy piping, piping components, and piping elements exposed to a fuel oil environment in the emergency diesel generator and auxiliary system, main fuel oil storage & transfer system, and fire protection system. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's fuel oil chemistry program (AMP B.1.24) and verified that this aging management program included activities that will mitigate loss of material due to pitting, crevice, and MIC. In addition, the project team reviewed the applicant's One-Time Inspection Program (B.1.24) and verified that this aging management program included inspections to detect loss of material due to pitting, crevice, and MIC as a means of verifying the effectiveness of the fuel oil chemistry program. The project team determined that these AMPs will adequately manage loss of material due to pitting, crevice, and MIC for steel piping, piping components, piping elements, and tanks exposed to fuel oil in the emergency diesel generator and auxiliary system, main fuel oil storage & transfer system, and fire protection system.

In Attachment 3, Item AP-54 of its reconciliation document, the applicant addressed loss of material of stainless steel piping, piping components, and piping elements exposed to fuel oil due to pitting, crevice, and MIC. The applicant stated that the line item for stainless steel piping elements in fuel oil, addressing loss of material due to corrosion, recommended the fuel oil chemistry program with no further evaluation required in the January 2005 draft GALL Report, and has been changed in the September 2005 GALL Report to recommend the fuel oil chemistry and One-Time Inspection Program, with a further evaluation of detected aging effects, to be consistent with other line items applicable to fuel oil environments. There are 6 instances of this line item being used, in the EDG and auxiliary systems, and in the main fuel oil storage and transfer system.

The applicant further stated that numerous items in the EDG and auxiliary systems, and main fuel oil storage systems are already subject to both the fuel oil chemistry and one-time inspection requirements for determination of loss of material due to corrosion. The basis for sample size for the One-Time Inspection Program would not be significantly affected by the addition of the (comparatively few) AP-54 line items. Evaluations of any detected aging effects from inspections of those components, with observed conditions that have the potential for impacting an intended function evaluated and corrected as necessary in accordance with the corrective action process, provide ample opportunity for verification of the effectiveness of the fuel oil chemistry program with the One-Time Inspection Program in these two systems. The applicant concluded that no change was necessary to the OCGS LRA due to this item.

The project team reviewed Table 3.3.2.1.13 in the OCGS LRA for the EDG and auxiliary system, and Table 3.3.2.1.21 in the OCGS LRA for the main fuel oil transfer system, and noted that there are multiple line items for components constructed of carbon steel, copper, and aluminum exposed to fuel oil that already credit both the fuel oil chemistry program and the One-Time Inspection Program to manage loss of material. Since stainless steel is expected to be more resistant to corrosion than carbon steel, copper, and aluminum, the later materials can be considered leading indicators and are expected to be included in the scope of the one-time inspection sample basis. Including one-time inspection for the stainless steel components would not significantly change the one-time inspection sample basis. On this basis, the project team determined that the fuel oil chemistry program is adequate to manage loss of material due to corrosion for the stainless steel components exposed to fuel oil in the EDG and auxiliary system, and the main fuel oil transfer system. The project team concurred with the applicant's conclusion that no change was needed to the OCGS LRA due to this item.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.3.2.2.12.1 for further evaluation.

3.3.2.2.12.2 Loss of Material Due to Pitting, Crevice, and Microbiologically Influenced Corrosion in Stainless Steel Exposed to Lubricating Oil [Item 2]

The project team reviewed OCGS LRA Section 3.3.2.2.12.2 against the criteria in SRP-LR Section 3.3.2.2.12.2.

SRP-LR Section 3.3.2.2.12.2 stated that loss of material due to pitting, crevice, and MIC could occur in stainless steel piping, piping components, and piping elements exposed to lubricating oil. The existing program relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. However, control of lube oil contaminants may not always have been adequate to preclude corrosion. Therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion is not occurring. The GALL Report recommended further evaluation of programs to manage corrosion to verify the effectiveness of the lubricating oil program. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In the OCGS LRA Section 3.3.2.2.12.2, the applicant addressed loss of material of stainless steel piping, piping components, and piping elements exposed to lubricating oil due to pitting, crevice, and MIC. The OCGS LRA stated that Oyster Creek will implement a One-Time Inspection Program, B.1.24, for susceptible locations to verify the effectiveness of the lubricating oil monitoring activities program, B.2.2, to manage the loss of material in stainless steel piping, piping components, and piping elements exposed to a lubricating oil environment in the emergency diesel generator and auxiliary system. The lubricating oil monitoring activities program manages physical and chemical properties of lubricating oil by sampling, testing, and trending to identify specific wear mechanisms, contamination, and oil degradation that could affect intended functions. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's further evaluation and determined that the lubricating oil monitoring activities program (AMP B.2.2) is a plant specific program that is appropriate to manage the loss of material in stainless steel piping, piping components, and piping elements exposed to a lubricating oil environment. The technical evaluation of this program to determine its adequacy was performed by NRC DE staff, and is addressed in the SER related to the Oyster Creek plant.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.3.2.2.12.2 for further evaluation.

3.3.2.2.13 <u>Loss of Material Due to Wear</u>

The project team reviewed OCGS LRA Section 3.3.2.2.13 against the criteria in SRP-LR Section 3.3.2.2.13.

SRP-LR Section 3.3.2.2.13 stated that loss of material due to wear could occur in the elastomer seals and components exposed to air indoor uncontrolled (internal or external). The GALL Report recommended further evaluation to ensure that these aging effects are adequately managed.

In the OCGS LRA, Section 3.3.2.2.13, the applicant addressed loss of material of elastomer seals and components exposed to air indoor uncontrolled (internal or external) due to wear. The OCGS LRA stated that Oyster Creek will implement a periodic inspection of ventilation systems program, B.2.4, for the inspection of elastomer door seals exposed to an indoor air internal or external environment in the ?C" battery room heating and ventilation system, 480V switchgear room ventilation system, battery and MG set room ventilation system, control room HVAC system, radwaste area heating and ventilation system, reactor building ventilation system, and standby gas treatment system. Periodic inspections are performed on elastomer door seals to identify detrimental changes in material properties, as evidenced by cracking, perforations in the material, or leakage. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's further evaluation and determined that the periodic inspection of ventilation systems program (AMP B.2.4) is a plant specific program that is appropriate to detect loss of material of elastomer seals and components. The technical evaluation of this program to determine its adequacy was performed by NRC DE staff, and is addressed in the SER related to the Oyster Creek plant.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.3.2.2.13 for further evaluation.

3.3.2.2.14 Loss of Material Due to Cladding Breach

Loss of material due to cladding breach for PWR steel charging pump casings with stainless steel cladding exposed to treated borated water is not applicable since Oyster Creek is a BWR plant.

3.3.2.2.15 Quality Assurance for Aging Management of Non-Safey-Related Components

OCGS LRA Section 3.3.2.2.15 is reviewed by NRR/DE staff and will be addressed separately in Section 3 of the SER related to the OCGS LRA.

Conclusion

On the basis of its review, for component groups evaluated in the GALL Report for which the GALL Report recommended further evaluation, the project team determined that the applicant adequately addressed the issues that were further evaluated.

3.3.2.3 *AMR Results That Are Not Consistent With The GALL Report Or Not Addressed In The GALL Report*

Summary of Information in the Application

In OCGS LRA Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems, the applicant provided information regarding components or material/environment combination in the GALL Report that it evaluated and identified as not applicable to its plant.

In OCGS LRA Tables 3.3.2.1.1 through 3.3.2.1.41, the applicant provided additional details of the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that are not consistent with the GALL Report. Specifically, the applicant indicated, via Notes F through J, that neither the identified component nor the material/environment combination is evaluated in the GALL Report and provided information concerning how the aging effect requiring management will be managed.

Project Team Evaluation

The project team reviewed additional details of the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that the applicant identified as not applicable to its plant or as having no aging effect.

The project team did not review the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that are not consistent with the GALL Report or are not addressed in the GALL Report. These AMR line items were reviewed by NRR/DE staff, and are discussed in the SER related to the OCGS LRA.

3.3.2.3.1 Aging Effects/mechanisms in Table 3.3.1 That Are Not Applicable for OCGS

The project team reviewed OCGS LRA Table 3.3.1, which provides a summary of aging management evaluations for the auxiliary systems evaluated in the GALL Report.

In OCGS LRA Table 3.3.1, Item 3.3.1-32, the applicant stated that cracking due to stress corrosion cracking for stainless steel and cast austenitic stainless steel piping, piping components, and piping elements exposed to treated water >140˚F is not applicable at OCGS. Oyster Creek has no stainless steel non-RCPB shutdown cooling system piping exposed to treated water >140˚F

The project team reviewed the auxiliary system AMR line items in the OCGS LRA and determined that Oyster Creek has no stainless steel non-RCPB shutdown cooling system piping exposed to treated water >140˚F. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.3.1, Item 3.3.1-34, the applicant stated that cracking due to cyclic loading, stress corrosion cracking for high-strength steel closure bolting exposed to air with steam or water leakage is not applicable at OCGS. Auxiliary system high-strength steel closure bolting exposed to air with steam or water leakage applies only to the control rod drive system. Control rod drive system high strength steel closure bolting is evaluated in Item Number 3.3.1-7.

The project team reviewed the auxiliary system AMR line items in the OCGS LRA and determined that auxiliary system high-strength steel closure bolting exposed to air with steam or water leakage applies only to the control rod drive system. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.3.1, Item 3.3.1-37, the applicant stated that loss of material due to general corrosion for steel closure bolting exposed to air with steam or water leakage is not applicable at OCGS. Except for control rod drive system high-strength steel closure bolting, which is evaluated in Item Number 3.3.1-7, auxiliary system steel closure bolting is not exposed to air with steam or water leakage.

The project team reviewed the auxiliary system AMR line items in the OCGS LRA and determined that, except for control rod drive system high-strength steel closure bolting which is evaluated in item number 3.3.1-7, auxiliary system steel closure bolting is not exposed to air with steam or water leakage. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.3.1, Item 3.3.1-44, the applicant stated that loss of material due to general, pitting, and crevice corrosion for steel compressed air system closure bolting exposed to condensation is not applicable at OCGS. Instrument (control) air system steel closure bolting is not exposed to condensation. Instrument (control) air system steel closure bolting exposed to an indoor air (external) environment is discussed in Item Number 3.3.1-35.

The project team reviewed the auxiliary system AMR line items in the OCGS LRA and determined that instrument (control) air system steel closure bolting is not exposed to condensation. Therefore, the project team concurred with the applicant’s conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.3.1, Item 3.3.1-45, the applicant stated that loss of material due to general and pitting corrosion for steel compressed air system piping, piping components, and piping elements exposed to condensation (internal) is not applicable at OCGS. Instrument (control) air piping, piping components, and piping elements are not exposed to a condensation (internal) environment. Instrument (control) air system piping, piping components, and piping elements exposed to a dry gas (internal) environment are discussed in Item Number 3.3.1-79 and 3.3.1-80.

The project team reviewed the auxiliary system AMR line items in the OCGS LRA and determined that instrument (control) air system piping, piping components, and piping elements are not exposed to a condensation (internal) environment. Therefore, the project team concurred with the applicant’s conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.3.1, Item 3.3.1-59, the applicant stated that loss of material due to pitting, crevice, and MIC for stainless steel and copper alloy piping, piping components, and piping elements exposed to raw water is not applicable at OCGS. There are no in-scope steel or copper alloy piping, piping components, and piping elements exposed to raw water in the Oyster Creek emergency diesel generator and auxiliary system. The diesels are cooled by radiators in a closed cooling water system.

The project team reviewed the auxiliary system AMR line items in the OCGS LRA and determined that there are no in-scope steel or copper alloy piping, piping components, and piping elements exposed to raw water in the Oyster Creek emergency diesel generator and auxiliary system. Therefore, the project team concurred with the applicant’s conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.3.1, Item 3.3.1-64, the applicant stated that loss of material due to lining or coating degradation for steel piping, piping components, and piping elements with internal lining or coating exposed to raw water is not applicable at OCGS. The presence of internal linings for corrosion protection is conservatively not credited. Degradation of internal coatings can contribute to potential downstream flow blockage. However NUREG-1801 Table IX.F under the aging mechanism of ?fouling" stated that reduction of system flow rate is considered active and thus not in the purview of license renewal. Therefore credit is not being taken for internal coating inspections.

The project team reviewed the auxiliary system AMR line items in the OCGS LRA and determined that the presence of internal linings for corrosion protection is conservatively not credited. Degradation of internal coatings can contribute to potential downstream flow blockage. However NUREG-1801 Table IX.F under the aging mechanism of ?fouling" stated that reduction of system flow rate is considered active and thus not in the purview of license renewal. Therefore credit is not being taken for internal coating inspections. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.3.1, Item 3.3.1-70, the applicant stated that cracking due to stress corrosion cracking for stainless steel spent fuel storage racks exposed to treated water or treated borated water, >60˚C (>140˚F) is not applicable at OCGS. Stainless steel spent fuel storage racks are exposed to a treated water <140˚F environment and are not susceptible to cracking. The loss of material aging effect for spent fuel storage racks exposed to a treated water <140˚F environment is evaluated in Item Number 3.3.1-22.

The project team reviewed the auxiliary system AMR line items in the OCGS LRA and determined that stainless steel spent fuel storage racks are exposed to a treated water <140˚F environment and are not susceptible to cracking. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

3.3.2.3.2 Auxiliary Systems AMR Line Items That Have No Aging Effect (OCGS LRA Tables 3.3.2.1.1 Through 3.3.2.1.41)

In OCGS LRA Tables 3.3.2.1.1 through 3.3.2.1.41, the applicant identified line-items where no aging effects were identified as a result of its aging review process.

In OCGS LRA Tables 3.3.2.1.1 through 3.3.2.1.41, the applicant identified AMR line-items where no aging effects were identified as a result of its aging review process. Specifically, instances in which the applicant stated that no aging effects were identified occurred when components fabricated from galvanized steel were exposed to an air-indoor uncontrolled environment.

The project team reviewed the recommendations in the GALL Report for this material/environment combination, and determined that the applicant's evaluations are consistent with the recommendations in the GALL Report. In addition, the project team reviewed the applicant's AMR technical basis documents listed in Attachment 5 of this audit and review report for the auxiliary systems, and determined that no significant aging effects were identified for auxiliary system components with this material/environment combination.

On the basis of its review of current industry research and operating experience, the project team found that galvanized steel exposed to an air-indoor uncontrolled environment will not result in aging that will be of concern during the period of extended operation. Therefore, the project team determined that there are no applicable aging effects requiring management for this material/environment combination.

In OCGS LRA Tables 3.3.2.1.1 through 3.3.2.1.41, the applicant identified AMR line-items where no aging effects were identified as a result of its aging review process. Specifically, instances in which the applicant stated that no aging effects were identified occurred when components fabricated from glass were exposed to an air, fuel oil, lubricating oil, raw water, or treated water environment.

The project team reviewed the recommendations in the GALL Report for these material/environment combinations, and determined that the applicant's evaluations are consistent with the recommendations in the GALL Report. In addition, the project team reviewed the applicant's AMR technical basis documents listed in Attachment 5 of this audit and review report for the auxiliary systems, and determined that no significant aging effects were identified for auxiliary system components with these material/environment combination.

On the basis of its review of current industry research and operating experience, the project team found that glass exposed to an air, fuel oil, lubricating oil, raw water, or treated water environment will not result in aging that will be of concern during the period of extended operation. Therefore, the project team determined that there are no applicable aging effects requiring management for these material/environment combinations.

In OCGS LRA Tables 3.3.2.1.1 through 3.3.2.1.41, the applicant identified AMR line-items where no aging effects were identified as a result of its aging review process. Specifically, instances in which the applicant stated that no aging effects were identified occurred when components fabricated from stainless steel, cast austenitic stainless steel, and nickel alloy were exposed to an air-indoor uncontrolled environment.

The project team reviewed the recommendations in the GALL Report for these material/environment combinations, and determined that the applicant's evaluations are consistent with the recommendations in the GALL Report. In addition, the project team reviewed the applicant's AMR technical basis documents listed in Attachment 5 of this audit and review report for the auxiliary systems, and determined that no significant aging effects were identified for auxiliary system components with these material/environment combination.

On the basis of its review of current industry research and operating experience, the project team found that stainless steel, cast austenitic stainless steel, and nickel alloy exposed to an air-indoor uncontrolled environment will not result in aging that will be of concern during the period of extended operation. Therefore, the project team determined that there are no applicable aging effects requiring management for these material/environment combinations.

In OCGS LRA Tables 3.3.2.1.1 through 3.3.2.1.41, the applicant identified AMR line-items where no aging effects were identified as a result of its aging review process. Specifically, instances in which the applicant stated that no aging effects were identified occurred when components fabricated from steel and aluminum were exposed to an air-indoor controlled environment.

The project team reviewed the recommendations in the GALL Report for these material/environment combinations, and determined that the applicant's evaluations are consistent with the recommendations in the GALL Report. In addition, the project team reviewed the applicant's AMR technical basis documents listed in Attachment 5 of this audit and review report for the auxiliary systems, and determined that no significant aging effects were identified for auxiliary system components with these material/environment combination.

On the basis of its review of current industry research and operating experience, the project team found that steel and aluminum exposed to an air-indoor controlled environment will not result in aging that will be of concern during the period of extended operation. Therefore, the project team determined that there are no applicable aging effects requiring management for these material/environment combinations.

In OCGS LRA Tables 3.3.2.1.1 through 3.3.2.1.41, the applicant identified AMR line-items where no aging effects were identified as a result of its aging review process. Specifically, instances in which the applicant stated that no aging effects were identified occurred when components fabricated from steel and stainless steel were exposed to a concrete environment.

The project team reviewed the recommendations in the GALL Report for these material/environment combinations, and determined that the applicant's evaluations are consistent with the recommendations in the GALL Report. In addition, the project team reviewed the applicant's AMR technical basis documents listed in Attachment 5 of this audit and review report for the auxiliary systems, and determined that no significant aging effects were identified for auxiliary system components with these material/environment combination.

On the basis of its review of current industry research and operating experience, the project team found that steel and stainless steel exposed to a concrete environment will not result in aging that will be of concern during the period of extended operation. Therefore, the project team determined that there are no applicable aging effects requiring management for these material/environment combinations.

In OCGS LRA Tables 3.3.2.1.1 through 3.3.2.1.41, the applicant identified AMR line-items where no aging effects were identified as a result of its aging review process. Specifically, instances in which the applicant stated that no aging effects were identified occurred when components fabricated from steel, stainless steel, aluminum, and copper alloy were exposed to a gas environment.

The project team reviewed the recommendations in the GALL Report for these material/environment combinations, and determined that the applicant's evaluations are consistent with the recommendations in the GALL Report. In addition, the project team reviewed the applicant's AMR technical basis documents listed in Attachment 5 of this audit and review report for the auxiliary systems, and determined that no significant aging effects were identified for auxiliary system components with these material/environment combination.

On the basis of its review of current industry research and operating experience, the project team found that steel, stainless steel, aluminum, and copper alloy exposed to a gas environment will not result in aging that will be of concern during the period of extended operation. Therefore, the project team determined that there are no applicable aging effects requiring management for these material/environment combinations.

In OCGS LRA Tables 3.3.2.1.1 through 3.3.2.1.41, the applicant identified AMR line-items where no aging effects were identified as a result of its aging review process. Specifically, instances in which the applicant stated that no aging effects were identified occurred when components fabricated from steel, stainless steel, and copper alloy were exposed to a lubricating oil (no water pooling) or dried air environment.

The project team reviewed the recommendations in the GALL Report for these material/environment combinations, and determined that the applicant's evaluations are consistent with the recommendations in the GALL Report. In addition, the project team reviewed the applicant's AMR technical basis documents listed in Attachment 5 of this audit and review report for the auxiliary systems, and determined that no significant aging effects were identified for auxiliary system components with these material/environment combination.

On the basis of its review of current industry research and operating experience, the project team found that steel, stainless steel, and copper alloy exposed to a lubricating oil (no water pooling) or dried air environment will not result in aging that will be of concern during the period of extended operation. Therefore, the project team determined that there are no applicable aging effects requiring management for these material/environment combinations.

Conclusion

On the basis of its review, the project team found that the applicant appropriately identified AMR results involving material, environment, aging effects requiring management, and AMP combinations that are not applicable to OCGS, and AMR results involving material and environment combinations that do not have aging effects requiring management at OCGS.

3.3.3 Conclusion

On the basis of its review, the project team determined that the applicant has demonstrated that the aging effects associated with the auxiliary system components will be adequately managed. The project team also reviewed the applicable UFSAR supplement program summaries and concluded that they adequately describe the AMPs credited for managing aging of the auxiliary system components, as required by 10 CFR 54.21(d).

3.4 OCGS LRA Section 3.4 – Aging Management of Steam and Power Conversion System

This section of the audit and review report documents the project team's review and evaluation of the OCGS aging management review (AMR) results for the aging management of the steam and power conversion system component and component groups associated with the following systems: (1) condensate system, (2) condensate transfer system, (3) feedwater system, (4) main condenser, (5) main generator and auxiliary system, (6) main steam system, and (7) main turbine and auxiliary system.

3.4.1 Summary of Technical Information in the Application

In the OCGS LRA Section 3.4, the applicant provided the results of its AMRs for the steam and power conversion system components and component groups.

In OCGS LRA Table 3.4.1, ?Summary of Aging Management Evaluations for Steam and Power Conversion System," the applicant provided a summary comparison of its AMR line-items with the AMR line-items evaluated in the GALL Report for the steam and power conversion system components and component groups. The applicant also identified for each component type in the OCGS LRA Table 3.4.1 those AMRs that are consistent with the GALL Report, those for which the GALL Report recommends further evaluation, and those AMRs that are not addressed in the GALL Report together with the basis for their exclusion.

In the OCGS LRA Tables 3.4.2.1.1 through 3.4.2.1.7, the applicant provided a summary of the AMR results for component types associated with (1) condensate system, (2) condensate transfer system, (3) feedwater system, (4) main condenser, (5) main generator and auxiliary system, (6) main steam system, and (7) main turbine and auxiliary system. Specifically, the information for each component type included intended function, material, environment, aging effect requiring management, AMPs, the GALL Report Volume 2 item, cross reference to the OCGS LRA Table 3.4.1 (Table 1), and generic and plant-specific notes related to consistency with the GALL Report.

The applicant's AMRs incorporated applicable operating experience in the determination of the aging effects requiring management (AERMs). These reviews included the evaluation of both plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.4.2 Project Team Evaluation

The project team reviewed OCGS LRA Section 3.4 to determine if the applicant provided sufficient information to demonstrate that the effects of aging for the steam and power conversion system components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The project team reviewed certain identified AMR line-items to confirm the applicant's claim that these AMR line-items were consistent with the GALL Report. The project team did not repeat its review of the matters described in the GALL Report. However, the project team did verify that the material presented in the OCGS LRA was applicable and that the applicant had identified the appropriate GALL Report AMR line-items. The project team's audit evaluation is documented in Section 3.4.2.1 of this audit and review report. In addition, the project team's evaluations of the AMPs are documented in Section 3.0.3 of this audit and review report.

The project team reviewed those selected AMR line-items for which further evaluation is recommended by the GALL Report. The project team confirmed that the applicant's further evaluations were in accordance with the acceptance criteria in the SRP-LR. The project team's audit evaluation is documented in Section 3.4.2.2 of this audit and review report.

The project team did not review the remaining AMR line-items that were not consistent with or not addressed in the GALL Report. These were reviewed by the NRC DE staff and documented in the SER for the Oyster Creek plant.

Finally, the project team reviewed the AMP summary descriptions in the UFSAR Supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the steam and power conversion system components.

Table 3.4-1 below provides a summary of the project team's evaluation of the components, aging effects/aging mechanisms, and AMPs listed in LRA Section 3.1 that are addressed in the GALL Report. It also includes the section of the audit and review report in which the project team's evaluation is documented. It should be noted that the line items in this table correspond to the line items in Table 3.4-1 of the September 2005 Revision 1 SRP-LR document; therefore, in many cases, they do not match the line items in Table 3.4.1 of the OCGS LRA. The SRP-LR line item number is denoted parenthetically in the column 1 entry. Also, line items that are applicable only to PWR plants are not included in this table; therefore, certain SRP-LR line item numbers do not appear in this table.

Table 3.4-1 Staff Evaluation for Steam and Power Conversion System Components in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Steel piping, piping components, and piping elements exposed to steam or treated water (Item 3.4.1-1)	Cumulative fatigue damage	TLAA evaluated in accordance with 10 CFR 54.21(c)	TLAA	Consistent with GALL, which recommends further evaluation. (See SER Section 3.4.2.2.1)
Steel piping, piping components, and piping elements exposed to steam (Item 3.4.1-2)	Loss of material due to general, pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Water Chemistry (B.1.2) and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. (See Audit Report Section 3.4.2.2.2.1)
Steel piping, piping components, and piping elements exposed to treated water (Item 3.4.1-4)	Loss of material due to general, pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Water Chemistry (B.1.2) and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. (See Audit Report Section 3.4.2.2.2.1)
Steel heat exchanger components exposed to treated water (Item 3.4.1-5)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Water Chemistry and One-Time Inspection	Water Chemistry (B.1.2) and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. (See Audit Report Section 3.4.2.2.9)
Steel and stainless steel tanks exposed to treated water (Item 3.4.1-6)	Loss of material due to general (steel only) pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Water Chemistry (B.1.2) and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. (See Audit Report Section 3.4.2.2.7.1 and 3.4.2.2.2.1 for steel tanks)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Steel piping, piping components, and piping elements exposed to lubricating oil (Item 3.4.1-7)	Loss of material due to general, pitting and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Lubricating Oil Monitoring Activities (B.2.2) and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. AMP B.2.2 reviewed by NRC DE staff. (See Audit Report Section 3.4.2.2.2.2)
Steel piping, piping components, and piping elements exposed to raw water (Item 3.4.1-8)	Loss of material due to general, pitting, crevice, and MIC corrosion, and fouling	Plant specific	Not Applicable	Not applicable, refers to auxiliary feedwater system of a PWR and is not applicable to Oyster Creek. (See Audit Report Section 3.4.2.2.3)
Stainless steel and copper alloy heat exchanger tubes exposed to treated water (Item 3.4.1-9)	Reduction of heat transfer due to fouling	Water Chemistry and One-Time Inspection	Not Applicable	Not applicable, there are no in-scope stainless steel heat exchanger tubes exposed to treated water with a heat transfer intended function in the steam and power conversion system at Oyster Creek (See Audit Report Section. 3.4.2.2.4.1)
Steel, stainless steel, and copper alloy heat exchanger tubes exposed to lubricating oil (Item 3.4.1-10)	Reduction of heat transfer due to fouling	Lubricating Oil Analysis and One-Time Inspection	Lubricating Oil Monitoring Activities (B.2.2)	AMR reviewed by NRR/DE staff. (See Audit Report Section. 3.4.2.2.4.2)
Buried steel piping, piping components, piping elements, and tanks (with or without coating or wrapping) exposed to soil (Item 3.4.1-11)	Loss of material due to general, pitting, crevice, and MIC corrosion	Buried Piping and Tanks Surveillance or Buried Piping and Tanks Inspection	Buried Piping Inspection (B.1.26)	Consistent with GALL, which recommends further evaluation (See Audit Report Section. 3.4.2.2.5.1)
Steel heat exchanger components exposed to lubricating oil (Item 3.4.1-12)	Loss of material due to general, pitting, crevice, and MIC corrosion	Lubricating Oil Analysis and One-Time Inspection	Not Applicable	Not Applicable – there are no steel heat exchanger components exposed to lubricating oil in the steam and power conversion system at Oyster Creek. (See Audit Report Section

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
				3.4.2.2.5.2)
Stainless steel piping, piping components, piping elements exposed to steam (Item 3.4.1-13)	Cracking due to stress corrosion cracking	Water Chemistry and One-Time Inspection	Water Chemistry (B.1.2) and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. (See Audit Report Section 3.4.2.2.6)
Stainless steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated water > 60°C (> 140°F) (Item 3.4.1-14)	Cracking due to stress corrosion cracking	Water Chemistry and One-Time Inspection	Water Chemistry (B.1.2) and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. (See Audit Report Section 3.4.2.2.6)
Aluminum and copper alloy piping, piping components, and piping elements exposed to treated water (Item 3.4.1-15)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Water Chemistry (B.1.2) and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. (See Audit Report Section 3.4.2.2.7.1)
Stainless steel piping, piping components, and piping elements; tanks, and heat exchanger components exposed to treated water (Item 3.4.1-16)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Water Chemistry (B.1.2) and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation (See Audit Report Section 3.4.2.2.7.1)
Stainless steel piping, piping components, and piping elements exposed to soil (Item 3.4.1-17)	Loss of material due to pitting and crevice corrosion	Plant specific	Buried Piping Inspection (B.1.26)	Consistent with GALL, which recommends further evaluation.. (See Audit Report Section 3.4.2.2.7.2)
Copper alloy piping, piping components, and piping elements exposed to lubricating oil (Item 3.4.1-18)	Loss of material due to pitting and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Not applicable	Not applicable, there are no in-scope copper alloy piping, piping components, or piping elements in the steam and power conversion system at Oyster Creek. (See Audit Report Section 3.4.2.2.7.3)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Stainless steel piping, piping components, piping elements, and heat exchanger components exposed to lubricating oil (Item 3.4.1-19)	Loss of material due to pitting, crevice, and MIC corrosion	Lubricating Oil Analysis and One-Time Inspection	Lubricating Oil Monitoring Activities (B.2.2) and One-Time Inspection (B.1.24)	Consistent with GALL, which recommends further evaluation. AMP B.2.2 reviewed by NR DE staff. (See Audit Report Section 3.4.2.2.8)
Steel tanks exposed to air – outdoor (external) (Item 3.4.1-20)	Loss of material/ general, pitting, and crevice corrosion	Aboveground Steel Tanks	Aboveground Outdoor Tanks (B.1.21)	Consistent with GALL. (See Audit Report Section 3.4.2.1)
High-strength steel closure bolting exposed to air with steam or water leakage (Item 3.4.1-21)	Cracking due to cyclic loading, stress corrosion cracking	Bolting Integrity	Not Applicable	Not applicable since no GALL AMR line items related to this component group/ aging effect combination were credited in the OCGS LRA.
Steel bolting and closure bolting exposed to air with steam or water leakage, air – outdoor (external), or air – indoor uncontrolled (external); (Item 3.4.1-22)	Loss of material due to general, pitting and crevice corrosion; loss of preload due to thermal effects, gasket creep, and self-loosening	Bolting Integrity	Bolting Integrity (B.1.12)	Consistent with GALL. (See Audit Report Section 3.4.2.1)
Stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water > 60°C (> 140°F) (Item 3.4.1-23)	Cracking due to stress corrosion cracking	Closed-Cycle Cooling Water System	Not Applicable	Not applicable since no GALL AMR line items related to this component group/ aging effect combination were credited in the OCGS LRA.
Steel heat exchanger components exposed to closed cycle cooling water (Item 3.4.1-24)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	Closed-Cycle Cooling Water System (B.1.14)	Consistent with GALL. (See Audit Report Section 3.4.2.1)
Stainless steel piping, piping components, piping elements, and heat	Loss of material due to pitting and crevice corrosion	Closed-Cycle Cooling Water System	Closed-Cycle Cooling Water System (B.1.14)	Consistent with GALL. (See Audit Report Section 3.4.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
exchanger components exposed to closed cycle cooling water (Item 3.4.1-25)				
Copper alloy piping, piping components, and piping elements exposed to closed cycle cooling water (Item 3.4.1-26)	Loss of material due to pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	Not Applicable.	Not applicable, there are no in-scope copper alloy components exposed to CCCW in the steam and power conversion system at Oyster Creek. (See Audit Report Section 3.4.2.3.1)
Steel, stainless steel, and copper alloy heat exchanger tubes exposed to closed cycle cooling water (Item 3.4.1-27)	Reduction of heat transfer due to fouling	Closed-Cycle Cooling Water System	Not Applicable.	Not applicable, there are no in-scope steel, stainless steel, or copper alloy heat exchanger tubes exposed to CCCW with heat transfer intended function in the steam and power conversion system at Oyster Creek. (See Audit Report Section 3.4.2.3.1)
Steel external surfaces exposed to air – indoor uncontrolled (external), condensation (external), or air outdoor (external) (Item 3.4.1-28)	Loss of material due to general corrosion	External Surfaces Monitoring	Structures Monitoring (B.1.31)	Acceptable – the OCGS structures monitoring program is consistent with the GALL external surfaces monitoring program for this component group/ aging effect combination. (See Audit Report Section 3.4.2.1)
Steel piping, piping components, and piping elements exposed to steam or treated water (Item 3.4.1-29)	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (B.1.11)	Consistent with GALL. (See Audit Report Section 3.4.2.1)
Steel piping, piping components, and piping elements exposed to air outdoor (internal) or	Loss of material due to general, pitting, and crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting	Periodic Inspection (B.2.5)	Acceptable – the OCGS periodic inspection program is appropriate for this component group/

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
condensation (internal) (Item 3.4.1-30)		Components		aging effect combination. AMP B.2.5 reviewed by NRR/DE staff. (See Audit Report Section 3.4.2.1)
Steel heat exchanger components exposed to raw water (Item 3.4.1-31)	Loss of material due to general, pitting, crevice, galvanic, and MIC corrosion, and fouling	Open-Cycle Cooling Water System	Not Applicable	Not applicable, there are no in-scope steel heat exchanger components exposed to raw water in the steam and power conversion system at Oyster Creek. (See Audit Report Section 3.4.2.3.1)
Stainless steel and copper alloy piping, piping components, and piping elements exposed to raw water (Item 3.4.1-32)	Loss of material due to pitting, crevice, and MIC corrosion	Open-Cycle Cooling Water System	Not Applicable	Not applicable, there are no in-scope stainless steel or copper alloy piping, piping components, or piping elements exposed to raw water in the steam and power conversion system at Oyster Creek Consistent with GALL. (See Audit Report Section 3.4.2.3.1)
Stainless steel heat exchanger components exposed to raw water (Item 3.4.1-33)	Loss of material due to pitting, crevice, and MIC corrosion, and fouling	Open-Cycle Cooling Water System	Not Applicable	Not applicable, there are no in-scope stainless steel heat exchanger components exposed to raw water in the steam and power conversion system at Oyster Creek. (See Audit Report Section 3.4.2.3.1)
Steel, stainless steel, and copper alloy heat exchanger tubes exposed to raw water (Item 3.4.1-34)	Reduction of heat transfer due to fouling	Open-Cycle Cooling Water System	Not Applicable	Not applicable, there are no in-scope steel, stainless steel, or copper alloy heat exchanger tubes exposed to raw water in the steam and power conversion system at Oyster Creek. (See Audit

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
				Report Section 3.4.2.3.1)
Copper alloy > 15% Zn piping, piping components, and piping elements exposed to closed cycle cooling water, raw water, or treated water (Item 3.4.1-35)	Loss of material due to selective leaching	Selective Leaching of Materials	Not Applicable	Not applicable, there are no in-scope copper alloy >15% Zn components exposed to CCCW or raw water in the steam and power conversion system at Oyster Creek. (See Audit Report Section 3.4.2.3.1)
Gray cast iron piping, piping components, and piping elements exposed to soil, treated water, or raw water (Item 3.4.1-36)	Loss of material due to selective leaching	Selective Leaching of Materials	Selective Leaching of Materials (B.1.25)	Consistent with GALL. (See Audit Report Section 3.4.2.1)
Steel, stainless steel, and nickel-based alloy piping, piping components, and piping elements exposed to steam (Item 3.4.1-37)	Loss of material due to pitting and crevice corrosion	Water Chemistry	Water Chemistry (B.1.2) and One-Time Inspection (B.1.24)	Consistent with GALL. (See Audit Report Section 3.4.2.1)
Glass piping elements exposed to air, lubricating oil, raw water, and treated water (Item 3.4.1-40)	None	None	None	Consistent with GALL. (See Audit Report Section 3.4.2.3.2)
Stainless steel, copper alloy, and nickel alloy piping, piping components, and piping elements exposed to air – indoor uncontrolled (external) (Item 3.4.1-41)	None	None	None	Consistent with GALL. (See Audit Report Section 3.4.2.3.2)
Steel piping, piping components, and piping elements exposed to air – indoor controlled	None	None	Not Applicable	Not Applicable Controlled air environments are not credited at Oyster Creek. Components

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
(external) (Item 3.4.1-42)				are evaluated as part of the uncontrolled indoor air environment. (See Audit Report Section 3.4.2.3.1)
Steel and stainless steel piping, piping components, and piping elements in concrete (Item 3.4.1-43)	None	None	Not Applicable	Not applicable. There are no in-scope steel or stainless steel piping, piping components, and piping elements in a concrete environment in the Steam and Power Conversion systems at Oyster Creek. (See Audit Report Section 3.4.2.3.1)
Steel, stainless steel, aluminum, and copper alloy piping, piping components, and piping elements exposed to gas (Item 3.4.1-44)	None	None	Not Applicable	Not applicable. There are no in-scope steel, stainless steel, aluminum, or copper alloy piping, piping components, and piping elements exposed to a gas environment in the Steam and Power Conversion systems at Oyster Creek. (See Audit Report Section 3.4.2.3.1)

3.4.2.1 *AMR Results That Are Consistent with The GALL Report*

Summary of Information in the Application

For aging management evaluations that the applicant stated are consistent with the GALL Report, the project team conducted its audit and review to determine if the applicant's reference to the GALL Report in the OCGS LRA is acceptable.

In OCGS LRA Section 3.4.1.2.1, the applicant identified the materials, environments, and aging effects requiring management. The applicant identified the following programs that manage the aging effects related to the condensate system, condensate transfer system, feedwater system, main condenser, main generator and auxiliary system, main steam system, and main turbine and auxiliary system components and component groups:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.1.1)
- Water Chemistry (B.1.2)

- FAC (B.1.11)
- Bolting Integrity (B.1.12)
- CCCWS (B.1.14)
- Aboveground Outdoor Tanks (B.1.21)
- One-Time Inspection (B.1.24)
- Selective Leaching of Materials (B.1.25)
- Buried Piping Inspection (B.1.26)
- Structures Monitoring Program (B.1.31)
- Lubricating Oil Monitoring Activities (B.2.2)
- Generator Stator Water Chemistry Activities (B.2.3)
- Periodic Inspection Program (B.2.5)

Project Team Evaluation

The project team reviewed its assigned OCGS LRA AMR line-items to determine that the applicant (1) provides a brief description of the system, components, materials, and environment; (2) stated that the applicable aging effects have been reviewed and are evaluated in the GALL Report; and (3) identifies those aging effects for the condensate system, condensate transfer system, feedwater system, main condenser, main generator and auxiliary system, main steam system, and main turbine and auxiliary system components that are subject to an AMR.

Loss of Material Due to Pitting and Crevice Corrosion

In the OCGS LRA, Table 3.4.2.1.6 for the main steam system included AMR line items for loss of material due to pitting anc crevice corrosion for carbon and low alloy steel components exposed to steam internal. The applicant proposed to manage this aging effect by crediting the OCGS Water Chemistry Program (AMP B.1.2) together with the OCGS One-Time Inspection Program (AMP B.1.24). In plant specific notes to Table 3.4.2.1.6 in the OCGS LRA, the applicant stated that the One-Time Inspection Program was applied in addition to the GALL Report recommended program for this aging effect. Generic note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report; however, a different aging management program was credited. The GALL Report recommended the Water Chemistry Program (XI.M2) alone to manage this aging effect.

The project team reviewed the applicant’s Water Chemistry Program (AMP B.1.2), verified that this program was consistent with the recommendations in the GALL Report for AMP XI.M2. Therefore, the project team determined that the applicant’s proposed inclusion of the One-Time Inspection Program, in addition to the GALL recommended program, will provide additional assurance that this aging effect will be adequately managed, and was acceptable.

On the basis of its review, the project team found that the applicant appropriately addressed loss of material due to pitting and crevice corrosion for steel components in a steam internal environment in the steam and power conversion systems.

Conclusion

The project team has evaluated the applicant's claim of consistency with the GALL Report. The project team also has reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the project team found that the AMR results, which the applicant claimed to be consistent with the GALL Report, are consistent with the AMRs in the GALL Report.

3.4.2.2 *AMR Results For Which Further Evaluation Is Recommended By The GALL Report*

Summary of Information in the Application

In OCGS LRA Section 3.4.2.2, the applicant provided further evaluation of aging management as recommended by the GALL Report for the condensate system, condensate transfer system, feedwater system, main condenser, main generator and auxiliary system, main steam system, and main turbine and auxiliary system components and component groups. The applicant also provided information concerning how it will manage the related aging effects.

Project Team Evaluation

For some AMR line-items assigned to the project team in Table 3.4.1 of the OCGS LRA, the GALL Report recommends further evaluation. When further evaluation was recommended, the project team reviewed these further evaluations provided in OCGS LRA Section 3.4.2.2 against the criteria provided in the SRP-LR Section 3.4.2.2. The project team's assessments of these evaluations is documented in this section. These assessments are applicable to each Table 2 AMR line-item in Section 3.4 citing the item in Table 1.

3.4.2.2.1 Cumulative Fatigue Damage

In LRA Section 3.4.2.2.1, the applicant stated that fatigue is a TLAA, as defined in 10 CFR 54.3. Applicants must evaluate TLAAs in accordance with 10 CFR 54.21(c)(1).

The project team noted that the OCGS LRA contains numerous AMR line items with references to TLAAs. All but a few cite cumulative fatigue damage as the aging effect requiring management, however it is not clear whether a CLB fatigue analysis actually exists or whether the TLAA is addressed by the assumed 7,000 cycles in accordance with B31.1 or equivalent design methods. The applicant was asked to identify the applicable disposition for each TLAA line item related to cumulative fatigue damage of mechanical components.

In its response, the applicant stated that there are two categories of fatigue TLAAs identified in the AMR tables. The first category is for components for which an explicit fatigue analysis exists, such as one performed in accordance with ASME Section III, Class 1 rules (or equivalent), with an associated Cumulative Usage Factor (CUF) value. The second category is for components that were designed in accordance with implicit fatigue design rules from ANSI B31.1 (or equivalent). The applicant provided a table that identifies whether a system or component has an explicit (E) or implicit (I) fatigue analysis associated with it.

The applicant further stated that, for license renewal, additional explicit fatigue analyses were prepared to consider the effects of environmental fatigue for the components identified in NUREG/CR-6260. These components are denoted in the table as also having an explicit environmental (E-env) fatigue analysis in addition to the original analysis. The components within each system bounded by the applicable environmental fatigue analysis are also denoted with a (E-env) in the table.

The applicant further stated that the table also includes a column denoting the disposition method used to manage the TLAA for the period of extended operation. The notation (I) indicates the existing analysis was determined to remain valid for the period of extended operation. The notation (ii) indicates the analysis was revised to become valid for the period of extended operation. The notation (iii) indicates fatigue monitoring will be used to assure the fatigue analysis will remain valid during the period of extended operation or will be reanalyzed as necessary prior to exceeding the design limit.

The project team reviewed the applicant's response, along with the table that identifies whether the TLAAs are implicit or explicit, and found it acceptable since it clarifies which TLAAs are based on an explicit calculation.

The evaluation of the TLAAs was performed by NRR/DE staff and is addressed separately in Section 4 of the SER related to the OCGS LRA

3.4.2.2.2 Loss of Material Due to General, Pitting, and Crevice Corrosion

3.4.2.2.2.1 Loss of Material Due to General, Pitting, and Crevice Corrosion [Item 1]

The project team reviewed OCGS LRA Section 3.4.2.2.2.1 against the criteria in SRP-LR Section 3.4.2.2.2.1.

SRP-LR Section 3.4.2.2.2.1 stated that loss of material due to general, pitting and crevice corrosion could occur for steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated water, and for steel piping, piping components, and piping elements exposed to steam. The existing aging management program relies on monitoring and control of water chemistry to manage the effects of loss of material due to general, pitting, and crevice corrosion. However, control of water chemistry does not preclude loss of material due to general, pitting, and crevice corrosion at locations of stagnant flow conditions. Therefore, the effectiveness of the water chemistry control program should be verified to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to verify the effectiveness of the water chemistry control program. A one-time inspection of select components and susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In the OCGS LRA Section 3.4.2.2.2.1, the applicant addressed the loss of material due to general, pitting, and crevice corrosion of steel and aluminum piping, piping components, and piping elements exposed to treated water, for steel heat exchanger shell side components exposed to treated water, and for steel piping, piping components, and piping elements exposed to steam. The OCGS LRA stated that Oyster Creek will implement a One-Time Inspection Program, B.1.24, for susceptible locations to verify the effectiveness of the Water Chemistry Program, B.1.2, to manage the loss of material in steel and aluminum piping, piping components, and piping elements exposed to a treated water environment, steel heat exchanger components exposed to steam or a treated water environment, and steel piping, piping components, and piping elements exposed to a steam environment in the condensate system, condensate transfer system, feedwater system, main steam system, main turbine and auxiliary system, emergency service water system, reactor building closed cooling water system, and heating and process steam system. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's Water Chemistry Program (AMP B.1.2) and verified that this aging management program included activities that monitor and control water chemistry to manage the effects of loss of material due to general, pitting, and crevice corrosion. In addition, the project team verified that the One-Time Inspection Program (AMP B.1.24) included inspection activities to verify the effectiveness of the Water Chemistry Program to manage loss of material due to general, pitting, and crevice corrosion at locations of stagnant flow conditions. The project team determined that these AMPs will adequately manage loss of material due to general, pitting and crevice corrosion for steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated water and for steel piping, piping components, and piping elements exposed to steam.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.4.2.2.2.1 for further evaluation.

3.4.2.2.2.2 <u>Loss of Material Due to General, Pitting, and Crevice Corrosion [Item 2]</u>

The project team reviewed OCGS LRA Section 3.4.2.2.2.2 against the criteria in SRP-LR Section 3.4.2.2.2.2.

SRP-LR Section 3.4.2.2.2.2 stated that loss of material due to general, pitting and crevice corrosion could occur for steel piping, piping components, and piping elements exposed to lubricating oil. The existing aging management program relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. However, control of lube oil contaminants may not always have been adequate to preclude corrosion. Therefore, the effectiveness of lubricating oil contaminant control should be verified to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of the lube oil chemistry control program. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In the OCGS LRA Section 3.4.2.2.2.2, the applicant addressed loss of material due to general, pitting and crevice corrosion for steel piping, piping components, and piping elements exposed to lubricating oil or steam. The OCGS LRA stated that a One-Time Inspection Program (AMP B.1.24 will be implemented for susceptible locations to verify the effectiveness of the lubricating oil monitoring activities program (AMP B.2.2) to manage the loss of material due to general, pitting and crevice corrosion for steel piping, piping components, and piping elements exposed to lubricating oil internal environment in the condensate system, condensate transfer system, feedwater system, main steam system, main turbine and auxiliary system, emergency service water system, reactor building closed cooling water system, and heating and process steam system. The lubricating oil monitoring activities program manages the physical and chemical properties of lubricating oil by sampling, testing, and trending to identify specific wear mechanisms, contamination, and oil degradation that could affect intended functions. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's further evaluation and determined that the lubricating oil monitoring activities program (AMP B.2.2) is a plant specific program that is appropriate to manage the loss of material due to general, pitting and crevice corrosion for steel piping, piping components, and piping elements exposed to lubricating oil internal environment. The technical evaluation of this program to determine its adequacy was performed by NRC DE staff, and is addressed in the SER related to the Oyster Creek plant.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.4.2.2.2.2 for further evaluation.

3.4.2.2.3 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion and Fouling

In Section 3.4.2.2.3 of the OCGS LRA, the applicant stated that loss of material due to general, pitting, crevice, and MIC, and fouling of steel components exposed to raw water in a PWR auxiliary feedwater system is applicable to PWRs only. The project team concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek is a BWR plant.

3.4.2.2.4 Reduction of Heat Transfer Due to Fouling

3.4.2.2.4.1 Reduction of Heat Transfer Due to Fouling [Item 1]

The project team noted that the applicant did not credit the GALL Report AMR for reduction of heat transfer due to fouling for stainless steel or copper alloy heat exchanger tubes exposed to treated water, which is associated with this further evaluation, for the Oyster Creek steam and power conversion systems.

The project team reviewed Tables 3.4.2.1.1 through 3.4.2.1.7 in the OCGS LRA for the steam and power conversion systems and noted that this component group/environment combination was not identified as being in the scope of license renewal. Therefore, the project team determined that this further evaluation is not applicable to Oyster Creek.

3.4.2.2.4.2 Reduction of Heat Transfer Due to Fouling [Item 2]

The project team noted that the applicant did not credit the GALL Report AMR for reduction of heat transfer due to fouling for steel, stainless steel, and copper alloy heat exchanger tubes exposed to lubricating oil, which is associated with this further evaluation, for the Oyster Creek steam and power conversion systems. This was a new AMR that was not in the draft January 2005 GALL Report.

The project team reviewed OCGS LRA Table 3.3.2.1.13 for the emergency diesel generator and auxiliary system, Table 3.3.2.1.15 for the fire protection system, and Table 3.3.2.1.29 for the RBCCW system and noted that the applicant identified copper alloy components exposed to lubricating oil for which the lubricating oil monitoring activities program (AMP B.2.2) was credited to manage reduction of heat transfer. Generic Note G was cited indicating that the environment was not in GALL for that component and material, therefore, these AMR line items were reviewed by NRC DE staff and are addressed in the SER for the Oyster Creek plant.

3.4.2.2.5 Loss of Material Due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion

3.4.2.2.5.1 Loss of Material Due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion [Item 1]

The applicant addressed loss of material due to general, pitting, crevice and MIC in steel components exposed to soil in OCGS Section 3.4.2.2.5.2, in accordance with the draft January 2005 SRP-LR. Therefore, the project team reviewed OCGS LRA Section 3.4.2.2.5.2 against the criteria in SRP-LR Section 3.4.2.2.5.1.

SRP-LR Section 3.4.2.2.5.1 stated that loss of material due to general, pitting and crevice corrosion, and MIC could occur in steel (with or without coating or wrapping) piping, piping components, piping elements and tanks exposed to soil. The buried piping and tanks inspection program relies on industry practice, frequency of pipe excavation, and operating experience to manage the effects of loss of material from general corrosion, pitting and crevice corrosion, and MIC. The effectiveness of the buried piping and tanks inspection program should be verified to evaluate an applicant's inspection frequency and operating experience with buried components, ensuring that loss of material is not occurring.

In the OCGS LRA Section 3.4.2.2.5.2, the applicant addressed loss of material of steel (with or without wrapping) piping, piping components, piping elements and tanks in soil due to general pitting and crevice corrosion, and MIC. The applicant stated that Oyster Creek will implement a buried pipe inspection program, B.1.26, to manage the loss of material in steel piping exposed to soil in the heating and process steam system. The Buried Piping Inspection Program includes preventive measures to mitigate corrosion and periodic inspection to manage the effects of corrosion on the pressure-retaining capacity of buried steel piping, piping components, and piping elements. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant’s Buried Piping Inspection Program (AMP B.1.26) and verified that this aging management program included inspections to detect loss of material of steel piping, piping components, and piping elements due to general, pitting, crevice corrosion, and MIC. The project team confirmed that, for each of the material/environment combinations for which the Buried Piping Inspection Program will be credited, at least one inspection (opportunistic or focused) has been, or will be performed prior to entering the extended period of operation, and a focused inspection will be performed within the 10-year period after entering the extended period of operation. The project team’s evaluation is documented in Section 3.3.2.2.8 of this audit and review report.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.4.2.2.5.1 for further evaluation.

3.4.2.2.5.2 Loss of Material Due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion [Item 2]

The project team noted that the applicant did not credit the GALL Report AMR for loss of material due to general, pitting and crevice corrosion, and MIC in steel heat exchanger components exposed to lubricating oil, which is associated with this further evaluation, for the Oyster Creek steam and power conversion systems.

The project team reviewed Tables 3.4.2.1.1 through 3.4.2.1.7 in the OCGS LRA for the steam and power conversion systems and noted that other GALL AMR line items that address same material/environment combinations were appropriately credited. Therefore, the project team determined that this further evaluation is not applicable to Oyster Creek.

3.4.2.2.6 Cracking Due to Stress Corrosion Cracking

The applicant addressed cracking due to SCC for stainless steel components exposed to treated water or steam in Section 3.4.2.2.6.1 of the OCGS LRA, in accordance with the draft January 2005 SRP-LR. Therefore, the project team reviewed OCGS LRA Section 3.4.2.2.6.1 against the criteria in SRP-LR Section 3.4.2.2.6

SRP-LR Section 3.4.2.2.6 stated that cracking due to SCC could occur in the stainless steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated water greater than 60˚C (>140˚F), and for stainless steel piping, piping components, and piping elements exposed to steam. The existing aging management program relies on monitoring and control of water chemistry to manage the effects of cracking due to SCC. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause SCC. Therefore, the GALL Report recommends that the effectiveness of the water chemistry control program should be verified to ensure that SCC is not occurring. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that SCC is not occurring and that the component's intended function will be maintained during the period of extended operation.

In the OCGS LRA Section 3.4.2.2.6.1, the applicant stated that Oyster Creek will implement a One-Time Inspection Program, B.1.24, for susceptible locations to verify the effectiveness of the Water Chemistry Program, B.1.2, to manage stress corrosion cracking of stainless steel piping, piping components, piping elements, and coolers exposed to treated water > 140˚F, or exposed to a steam environment in the feedwater system, heating & process steam system, main steam system, isolation condenser system, shutdown cooling system, and main turbine auxiliary system. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's Water Chemistry Program (AMP B.1.2) and verified that this aging management program include activities that will mitigate cracking due to SCC. In addition, the project team reviewed the applicant's One-Time Inspection Program (B.1.24) and verified that this aging management program includes inspections of the stainless steel steam and power conversion system components to detect cracking as a means of verifying the effectiveness of the Water Chemistry Program. The project team determined that these AMPs will adequately manage cracking due to SCC for stainless steel heat exchanger components in the steam and power conversion systems.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.4.2.2.6 for further evaluation.

3.4.2.2.7 Loss of Material Due to Pitting and Crevice Corrosion

3.4.2.2.7.1 Loss of Material Due to Pitting and Crevice Corrosion [Item 1]

The project team reviewed OCGS LRA Section 3.4.2.2.7.1 against the criteria in SRP-LR Section 3.4.2.2.7.1.

SRP-LR Section 3.4.2.2.7.1 stated that loss of material due to pitting and crevice corrosion could occur for stainless steel, aluminum, and copper alloy piping, piping components and piping elements and for stainless steel tanks and heat exchanger components exposed to treated water. The existing aging management program relies on monitoring and control of water chemistry to manage the effects of loss of material due to pitting, and crevice corrosion. However, control of water chemistry does not preclude corrosion at locations of stagnant flow conditions. Therefore, the GALL Report recommends that the effectiveness of the Water Chemistry Program should be verified to ensure that corrosion is not occurring. A one-time inspection of select components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In the OCGS LRA Section 3.4.2.2.7.1, the applicant addressed loss of material of stainless steel, aluminum, and copper alloy piping, piping components and piping elements and for stainless steel tanks and heat exchanger components due to pitting and crevice corrosion . The OCGS LRA stated that Oyster Creek will implement a One-Time Inspection Program, B.1.24, for susceptible locations to verify the effectiveness of the Water Chemistry Program, B.1.2, to manage the loss of material in stainless steel, piping components, piping elements, tanks, and heat exchanger shell-side components exposed to a treated water environment in the condensate system, feedwater system, main steam system, main turbine and auxiliary system, and reactor water cleanup system. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant’s Water Chemistry Program (AMP B.1.2) and verified that this aging management program include activities that will mitigate cracking due to SCC. In addition, the project team reviewed the applicant’s One-Time Inspection Program (B.1.24) and verified that this aging management program includes inspections of the stainless steel, aluminum, and copper alloy steam and power conversion system components to detect cracking as a means of verifying the effectiveness of the Water Chemistry Program. The project team determined that these AMPs will adequately manage cracking due to SCC for stainless steel, piping components, piping elements, tanks, and heat exchanger shell-side components exposed to a treated water environment in the steam and power conversion systems.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.4.2.2.7.1 for further evaluation.

3.4.2.2.7.2 Loss of Material Due to Pitting and Crevice Corrosion [Item 2]

The project team reviewed OCGS LRA Section 3.4.2.2.7.2 against the criteria in SRP-LR Section 3.4.2.2.7.2.

SRP-LR Section 3.4.2.2.7.2 stated that loss of material due to pitting and crevice corrosion could occur for stainless steel piping, piping components, and piping elements exposed to soil. The GALL Report recommends further evaluation of a plant-specific aging management to ensure that this aging effect is adequately managed.

In the OCGS LRA Section 3.4.2.2.7.2, the applicant addressed loss of material of stainless steel piping, piping components, and piping elements due to pitting and crevice corrosion. The OCGS LRA stated that Oyster Creek will implement a Buried Piping Inspection Program, B.1.26, to manage the loss of material in stainless steel piping exposed to soil in the heating and process steam system. The Buried Piping Inspection Program includes preventive measures to mitigate corrosion and periodic inspection to manage the effects of corrosion on the pressure-retaining capacity of buried stainless steel piping. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant's Buried Piping Inspection Program (AMP B.1.26) and verified that this aging management program included inspections to detect loss of material of stainless steel piping due to pitting and crevice corrosion. The project team confirmed that, for each of the material/environment combinations for which the Buried Piping Inspection Program will be credited, at least one inspection (opportunistic or focused) has been, or will be performed prior to entering the extended period of operation, and a focused inspection will be performed within the 10-year period after entering the extended period of operation. The project team's evaluation is documented in Section 3.3.2.2.8 of this audit and review report.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.4.2.2.7.2 for further evaluation.

3.4.2.2.7.3 Loss of Material Due to Pitting and Crevice Corrosion [Item 3]

The applicant addressed loss of material due to pitting and crevice corrosion for copper alloy components exposed to lubricating oil in Section 3.4.2.2.9 of the OCGS LRA, in accordance with the draft January 2005 SRP-LR. Therefore, the project team reviewed OCGS LRA Section 3.4.2.2.9 against the criteria in SRP-LR Section 3.4.2.2.7.3.

SRP-LR Section 3.4.2.2.7.3 stated that loss of material due to pitting and crevice corrosion could occur for copper alloy piping, piping components, and piping elements exposed to lubricating oil. The existing aging management program relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. However, control of lube oil contaminants may not always have been adequate to preclude corrosion. Therefore, the effectiveness of lubricating oil contaminant control should be verified to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of the lube oil chemistry control program. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In the OCGS LRA Section 3.4.2.2.9, the applicant stated that this line item is not used at Oyster Creek. At Oyster Creek, there are no in-scope copper alloy piping, piping components, and piping elements in a lubricating oil environment in the steam and power conversion systems.

The project team reviewed Tables 3.4.2.1.1 through 3.4.2.1.7 in the OCGS LRA for the steam and power conversion systems and verified that no copper alloy piping, piping components, or piping elements were identified in the scope of license renewal. Therefore, the project team concurred with the applicant's conclusion that this further evaluation is not applicable to Oyster Creek.

3.4.2.2.8 Loss of Material Due to Pitting, Crevice, and Microbiologically Influenced Corrosion

The project team reviewed OCGS LRA Section 3.4.2.2.8 against the criteria in SRP-LR Section 3.4.2.2.8.

SRP-LR Section 3.4.2.2.8 stated that loss of material due to pitting, crevice, and MIC could occur in stainless steel piping, piping components, piping elements, and heat exchanger components exposed to lubricating oil. The existing aging management program relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. However, control of lube oil contaminants may not always have been adequate to preclude corrosion. Therefore, the effectiveness of lubricating oil contaminant control should be verified to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of the lube oil chemistry control program. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In the OCGS LRA Section 3.4.2.2.8, the applicant addressed loss of material of stainless steel piping, piping components, and piping elements due to pitting, crevice, and MIC. The OCGS LRA stated that Oyster Creek will implement a One-Time Inspection Program, B.1.24, for susceptible locations to verify the effectiveness of the lubricating oil monitoring activities program, B.2.2, to manage the loss of material in stainless steel piping, piping components, and piping elements exposed to lubricating oil internal environment in the main turbine and auxiliary system. The lubricating oil monitoring activities program manages physical and chemical properties of lubricating oil by sampling, testing, and trending to identify specific wear mechanisms, contamination, and oil degradation that could affect intended functions. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant’s further evaluation and determined that the lubricating oil monitoring activities program (AMP B.2.2) is a plant specific program that is appropriate to manage the loss of material in stainless steel piping, piping components, and piping elements exposed to lubricating oil internal environment. The technical evaluation of this program to determine its adequacy was performed by NRC DE staff, and is addressed in the SER related to the Oyster Creek plant.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.4.2.2.8 for further evaluation.

3.4.2.2.9 Loss of Material Due to General, Pitting, Crevice, and Galvanic Corrosion

The applicant addressed loss of material due to general, pitting, crevice, and galvanic corrosion for steel heat exchanger components in OCGS LRA Section 3.4.2.2.2.1, in accordance with the draft January 2005 GALL Report. Therefore, the project team reviewed OCGS LRA Section 3.4.2.2.2.1 against the criteria in SRP-LR Section 3.4.2.2.9.

SRP-LR Section 3.4.2.2.9 stated that loss of material due to general, pitting, crevice, and galvanic corrosion can occur for steel heat exchanger components exposed to treated water. The existing aging management program relies on monitoring and control of water chemistry to manage the effects of loss of material due to general, pitting, and crevice corrosion. However, control of water chemistry does not preclude loss of material due to general, pitting, and crevice corrosion at locations of stagnant flow conditions. Therefore, the effectiveness of the water chemistry control program should be verified to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to verify the effectiveness of the water chemistry control program. A one-time inspection of select components and susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In the OCGS LRA Section 3.4.2.2.2.1, the applicant addressed loss of material of steel and aluminum piping, piping components, and piping elements due to general, pitting, and crevice corrosion. The OCGS LRA stated that Oyster Creek will implement a One-Time Inspection Program, B.1.24, for susceptible locations to verify the effectiveness of the Water Chemistry Program, B.1.2, to manage the loss of material in steel and aluminum piping, piping components, and piping elements exposed to a treated water environment, steel heat exchanger components exposed to a steam or treated water environment, and steel piping, piping components, and piping elements exposed to a steam environment in the condensate system, condensate transfer system, feedwater system, main steam system, main turbine and auxiliary system, emergency service water system, reactor building closed cooling water system, and heating and process steam system. The One-Time Inspection Program also will be used to verify the effectiveness of the Water Chemistry Program to manage the loss of material in steel shell and shell side components exposed to a treated water environment in the isolation condenser system. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

The project team reviewed the applicant’s Water Chemistry Program (AMP B.1.2) and verified that this aging management program include activities that will manage loss of material due to general, pitting, crevice, and galvanic corrosion for steel heat exchanger components. In addition, the project team reviewed the applicant’s One-Time Inspection Program (B.1.24) and verified that this aging management program includes inspections to detect cracking as a means of verifying the effectiveness of the Water Chemistry Program. The project team determined that these AMPs will adequately manage loss of material for steel heat exchanger components exposed to a treated water environment in the steam and power conversion systems.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.4.2.2.9 for further evaluation.

3.4.2.2.10 Quality Assurance for Aging Management of Non-Safety-Related Components

OCGS LRA Section 3.4.2.2.10 was reviewed by NRR/DE staff and was addressed separately in Section 3 of the SER related to the OCGS LRA.

Conclusion

On the basis of its review, for component groups evaluated in the GALL Report for which the GALL Report recommends further evaluation, the project team determined that the applicant adequately addressed the issues that were further evaluated.

3.4.2.3 *AMR Results That Are Not Consistent With The GALL Report Or Not Addressed In The GALL Report*

Summary of Information in the Application

In OCGS LRA Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion System, the applicant provided information regarding components or material/environment combination in the GALL Report that it evaluated and identified as not applicable to its plant.

In OCGS LRA Tables 3.4.2.1.1 through 3.4.2.1.7, the applicant provided additional details of the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that are not consistent with the GALL Report. Specifically, the applicant indicated, via Notes F through J, that neither the identified component nor the material/ environment combination is evaluated in the GALL Report and provided information concerning how the aging effect requiring management will be managed.

Project Team Evaluation

The project team reviewed additional details of the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that the applicant identified as not having any aging effect, or as not applicable to its plant.

The project team did not review the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that are not consistent with the GALL Report or are not addressed in the GALL Report. These AMR line items were reviewed by NRR/DE staff, and are discussed in the SER related to the OCGS LRA.

3.4.2.3.1 Aging Effect/Mechanism in Table 3.4.1 That Are Not Applicable for OCGS

The project team reviewed OCGS LRA Table 3.4.1, which provides a summary of aging management evaluations for the steam and power conversion system evaluated in the GALL Report.

In OCGS LRA Table 3.4.1, Item 3.4.1-14, the applicant stated that loss of material due to pitting, crevice and galvanic corrosion for copper alloy piping, piping components, and piping elements exposed to closed-cycle cooling water is not applicable at OCGS. There are no in-scope copper alloy components exposed to closed cycle cooling water in the steam and power conversion systems at Oyster Creek.

The project team reviewed the AMR line items in Tables 3.4.2.1 through 3.4.2.7 in the OCGS LRA for the steam and power conversion systems, and determined that Oyster Creek has no in-scope copper alloy components exposed to closed cycle cooling water. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.4.1, Item 3.4.1-15, the applicant stated that loss of material due to selective leaching for copper alloy >15% Zn piping, piping components, and piping elements exposed to closed-cycle cooling water or raw water is not applicable at OCGS. There are no in-scope copper alloy components exposed to closed cycle cooling water or raw water in the steam and power conversion systems at Oyster Creek, except the main condenser tubesheet. In the LRA, applicant stated that based on past precedence (NUREG-1796, Dresden and Quad Cities SER, Section 3.4.2.4.4 and NUREG-1769, Peach Bottom SER, Section 3.4.2.3), the staff concluded that the main condenser integrity is continually verified during normal plant operation and no aging management program is required to assure the post-accident intended function.

The project team reviewed the AMR line items in Tables 3.4.2.1.1 through 3.4.2.1.7 in the OCGS LRA for the steam and power conversion systems, and determined that Oyster Creek has no in-scope copper alloy >15% Zn components exposed to closed cycle cooling water or raw water. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.4.1, Item 3.4.1-18, the applicant stated that reduction of heat transfer due to fouling for stainless steel heat exchanger tubes exposed to closed-cycle cooling water is not applicable at OCGS. There are no in-scope stainless steel heat exchanger tubes exposed to a closed cycle cooling water environment with a heat transfer intended function in the steam and power conversion systems at Oyster Creek.

The project team reviewed the AMR line items in Tables 3.4.2.1.1 through 3.4.2.1.7 in the OCGS LRA for the steam and power conversion systems, and determined that Oyster Creek has no in-scope stainless steel heat exchanger tubes exposed to closed cycle cooling water. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.4.1, Item 3.4.1-19, the applicant stated that loss of material due to pitting, crevice, and MIC for stainless steel heat exchanger tube side components exposed to raw water is not applicable at OCGS. There are no in-scope stainless steel heat exchanger tube side components exposed to a raw water environment at Oyster Creek.

The project team reviewed the AMR line items in Tables 3.4.2.1.1 through 3.4.2.1.7 in the OCGS LRA for the steam and power conversion systems, and determined that Oyster Creek has no in-scope stainless steel heat exchanger tube side components exposed to raw water. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.4.1, Item 3.4.1-20, the applicant stated that cracking due to stress corrosion cracking for stainless steel piping, piping components, and piping elements exposed to steam is not applicable at OCGS. This item applies to the main steam system of a PWR, and is not applicable to Oyster Creek.

The project team concurred with the applicant's conclusion that this item applies to the main steam system of a PWR, and is not applicable to Oyster Creek.

In OCGS LRA Table 3.4.1, Item 3.4.1-21, the applicant stated that reduction of heat transfer due to fouling for stainless steel heat exchanger tubes exposed to treated water is not applicable at OCGS. There are no in-scope stainless steel heat exchanger tubes exposed to a treated water environment with a heat transfer intended function in the steam and power conversion systems at Oyster Creek.

The project team reviewed the AMR line items in Tables 3.4.2.1.1 through 3.4.2.1.7 in the OCGS LRA for the steam and power conversion systems, and determined that Oyster Creek has no in-scope stainless steel heat exchanger tubes exposed to treated water. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.4.1, Item 3.4.1-22, the applicant stated that loss of material due to pitting, crevice and MIC for stainless steel and copper alloy piping, piping components, and piping elements exposed to raw water is not applicable at OCGS. There are no in-scope stainless steel or copper alloy components exposed to raw water in the steam and power conversion systems at Oyster Creek, except the main condenser tubesheet. Based on past precedence (NUREG-1796, Dresden and Quad Cities SER, Section 3.4.2.4.4 and NUREG-1769, Peach Bottom SER, Section 3.4.2.3), the staff concluded that the main condenser integrity is continually verified during normal plant operation and no aging management program is required to assure the post-accident intended function.

The project team reviewed the AMR line items in Tables 3.4.2.1 through 3.4.2.7 in the OCGS LRA for the steam and power conversion systems, and determined that Oyster Creek has no in-scope stainless steel or copper alloy piping, piping components, and piping elements exposed to raw water. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.4.1, Item 3.4.1-25, the applicant stated that loss of material due to general, pitting, crevice and MIC for steel heat exchanger tube side components exposed to raw water is not applicable at OCGS. There are no in-scope steel heat exchanger tube side components exposed to raw water at Oyster Creek.

The project team reviewed the AMR line items in Tables 3.4.2.1 through 3.4.2.7 in the OCGS LRA for the steam and power conversion systems, and determined that Oyster Creek has no in-scope steel heat exchanger tube side components exposed to raw water. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.4.1, Item 3.4.1-28, the applicant stated that reduction of heat transfer due to fouling for steel and stainless steel heat exchanger tubes exposed to raw water is not applicable at OCGS. There are no in-scope steel or stainless steel heat exchanger tubes exposed to a raw water environment in the steam and power conversion systems at Oyster Creek.

The project team reviewed the AMR line items in Tables 3.4.2.1.1 through 3.4.2.1.7 in the OCGS LRA for the steam and power conversion systems, and determined that Oyster Creek has no in-scope steel or stainless steel heat exchanger tubes exposed to raw water. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.4.1, Item 3.4.1-33, the applicant stated that steel piping, piping components, and piping elements exposed to air-indoor controlled (external) is not applicable at OCGS. Controlled air environments are not credited at Oyster Creek. Components are evaluated as part of the uncontrolled indoor air environment.

The project team reviewed the AMR line items in Tables 3.4.2.1.1 through 3.4.2.1.7 in the OCGS LRA for the steam and power conversion systems, and determined that Oyster Creek has no steel piping, piping components, or piping elements exposed to an air-indoor controlled (external) environment. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.4.1, Item 3.4.1-34, the applicant stated that steel and stainless steel piping, piping components, and piping elements in concrete is not applicable at OCGS. There are no in-scope steel or stainless steel piping, piping components, and piping elements in a concrete environment in the steam and power conversion systems at Oyster Creek.

The project team reviewed the AMR line items in Tables 3.4.2.1.1 through 3.4.2.1.7 in the OCGS LRA for the steam and power conversion systems, and determined that Oyster Creek has no steel or stainless steel piping, piping components, or piping elements in concrete. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.4.1, Item 3.4.1-35, the applicant stated that steel, stainless steel, aluminum, and copper alloy piping, piping components, and piping elements exposed to gas is not applicable at OCGS. There are no in-scope steel, stainless steel, aluminum, or copper alloy piping, piping components, and piping elements exposed to a gas environment in the steam and power conversion systems at Oyster Creek.

The project team reviewed the AMR line items in Tables 3.4.2.1.1 through 3.4.2.1.7 in the OCGS LRA for the steam and power conversion systems, and determined that Oyster Creek has no in-scope steel, stainless steel, aluminum, or copper alloy piping, piping components, or piping elements exposed to a gas environment. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

In OCGS LRA Table 3.4.1, Item 3.4.1-36, the applicant stated that steel, stainless steel and copper alloy piping, piping components, and piping elements exposed to lubricating oil (no water pooling) is not applicable at OCGS. Lubricating oil (no water pooling) is not credited at Oyster Creek. Components are evaluated as part of the lubricating oil environment.

The project team reviewed the AMR line items in Tables 3.4.2.1.1 through 3.4.2.1.7 in the OCGS LRA for the steam and power conversion systems, and determined that Oyster Creek has no in-scope steel, stainless steel or copper alloy piping, piping components, or piping elements exposed to a lubricating oil (no water pooling) environment. Therefore, the project team concurred with the applicant's conclusion that this aging effect is not applicable to Oyster Creek.

On the basis that none of the component groups addressed in this AMR are in the scope of license renewal, the project team found that, for this component group, this aging effect is not applicable to OCGS.

3.4.2.3.2 Steam and Power Conversion System AMR Line Items That Have No Aging Effect (OCGS LRA Tables 3.4.2.1.1 Through 3.4.2.1.7)

In OCGS LRA Tables 3.4.2.1.1 through 3.4.2.1.7, the applicant identified line-items where no aging effects were identified as a result of its aging review process.

In OCGS LRA Tables 3.4.2.1.1 through 3.4.2.1.7, the applicant identified AMR line-items where no aging effects were identified as a result of its aging review process. Specifically, instances in which the applicant stated that no aging effects were identified occurred when components fabricated from glass were exposed to an air, lubricating oil, raw water, and treated water environment.

The project team reviewed the recommendations in the GALL Report for this material/environment combination, and determined that the applicant's evaluations are consistent with the recommendations in the GALL Report. In addition, the project team reviewed the applicant's AMR technical basis documents listed in Attachment 5 of this audit and review report for the steam and power conversion systems, and determined that no significant aging effects were identified for components with this material/environment combination.

On the basis of its review of current industry research and operating experience, the project team found that glass exposed to an air, lubricating oil, raw water, or treated water environment will not result in aging that will be of concern during the period of extended operation. Therefore, the project team determined that there are no applicable aging effects requiring management for this material/environment combination.

In OCGS LRA Tables 3.4.2.1.1 through 3.4.2.1.7, the applicant identified AMR line-items where no aging effects were identified as a result of its aging review process. Specifically, instances in which the applicant stated that no aging effects were identified occurred when components fabricated from stainless steel were exposed to an air-indoor uncontrolled environment.

The project team reviewed the recommendations in the GALL Report for this material/environment combination, and determined that the applicant's evaluations are consistent with the recommendations in the GALL Report. In addition, the project team reviewed the applicant's AMR technical basis documents listed in Attachment 5 of this audit and review report for the steam and power conversion systems, and determined that no significant aging effects were identified for components with this material/environment combination.

On the basis of its review of current industry research and operating experience, the project team found that stainless steel exposed to an air-indoor uncontrolled environment will not result in aging that will be of concern during the period of extended operation. Therefore, the project team determined that there are no applicable aging effects requiring management for this material/environment combination.

Conclusion

On the basis of its review, the project team found that the applicant appropriately identified AMR results involving material, environment, aging effects requiring management, and AMP combinations that are not applicable to OCGS, and AMR results involving material and environment combinations that do not have aging effects requiring management at OCGS.

3.4.3 Conclusion

On the basis of its review, the project team determined that the applicant has demonstrated that the aging effects associated with the steam and power conversion system components will be adequately managed.

The project team also reviewed the applicable UFSAR supplement program summaries and concludes that they adequately describe the AMPs credited for managing aging of the steam and power conversion components, as required by 10 CFR 54.21(d).

3.5 OCGS LRA Section 3.5 – Aging Management of Primary Containment, Structures, Component Supports, and Piping and Component Insulation

This section of the audit and review report document the project team's review and evaluation of OCGS aging management review (AMR) results for the aging management of the primary containment, structures, component supports, and piping and component insulation component and component groups associated with the following systems: (1) primary containment, (2) reactor building, (3) chlorination facility, (4) condensate transfer building, (5) dilution structure, (6) emergency diesel generator building, (7) exhaust tunnel, (8) fire pond dam, (9) fire pumphouses, (10) heating boiler house, (11) intake structure and canal, (12) miscellaneous yard structures, (13) new radwaste building, (14) office building, (15) oyster creek substation, (16) turbine building, (17) ventilation stack, (18) component supports commodity group and, (19) piping and component insulation commodity group.

3.5.1 Summary of Technical Information in the Application

In the OCGS LRA Section 3.5, the applicant provided the results of its AMRs for structures.

In OCGS LRA Table 3.5.2, ?Summary of Aging Management Primary Containment, Structures, Component Supports, and Piping and Component Insulation," the applicant provided a summary comparison of its AMR line-items with the AMR line-items evaluated in the GALL Report for the primary containment, structures, component supports, and piping and component insulation components and component groups. The applicant also identified for each component type in the OCGS LRA Table 3.5.1 those components that are consistent with the GALL Report, those for which the GALL Report recommends further evaluation, and those components that are not addressed in the GALL Report, together with the basis for their exclusion.

In the OCGS LRA Tables 3.5.2.1.1 through 3.5.2.1.19, the applicant provided a summary of the AMR results for component types associated with (1) primary containment, (2) reactor building, (3) chlorination facility, (4) condensate transfer building, (5) dilution structure, (6) emergency diesel generator building, (7) exhaust tunnel, (8) fire pond dam, (9) fire pumphouses, (10) heating boiler house, (11) intake structure and canal, (12) miscellaneous yard structures, (13) new radwaste building, (14) office building, (15) oyster creek substation, (16) turbine building, (17) ventilation stack, (18) component supports commodity group and, (19) piping and component insulation commodity group. Specifically, the information for each component type included intended function, material, environment, aging effect requiring management, AMPs, the GALL Report Volume 2 item, cross reference to the OCGS LRA Table 3.5.1 (Table 1), and generic and plant-specific notes related to consistency with the GALL Report.

The applicant's AMRs incorporated applicable operating experience in the determination of aging effect requiring managements (AERMs). These reviews included evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.5.2 Project Team Evaluation

The project team reviewed OCGS LRA Section 3.5 to determine if the applicant provided sufficient information to demonstrate that the effects of aging for the primary containment, structures, component supports, and piping and component insulation components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The project team reviewed certain identified AMR line-items to confirm the applicant's claim that these AMR line-items were consistent with the GALL Report. The project team did not repeat its review of the matters described in the GALL Report. However, the project team did verify that the material presented in the OCGS LRA was applicable and that the applicant had identified the appropriate GALL Report AMR line-items. The project team's audit evaluation is documented in Section 3.5.2.1 of this audit and review report. In addition, the project team's evaluations of the AMPs are documented in Section 3.0.3 of this audit and review report.

The project team reviewed those selected AMR line-items for which further evaluation is recommended by the GALL Report. The project team confirmed that the applicant's further evaluations were in accordance with the acceptance criteria in SRP-LR. The project team's audit evaluation is documented in Section 3.5.2.2 of this audit and review report.

The project team did not review the remaining AMR line-items that were not consistent with or not addressed in the GALL Report. These were reviewed by the NRR/DE staff and documented in the SER for the Oyster Creek plant.

Finally, the project team reviewed the AMP summary descriptions in the UFSAR Supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the primary containment, structures, component supports, and piping and component insulation components.

Table 3.5-1 below provides a summary of the project team's evaluation of components, aging effects/aging mechanisms, and AMPs listed in LRA Section 3.5 that are addressed in the GALL Report. It also includes the section of the audit and review report in which the project team's evaluation is documented. It should be noted that the line items in this table correspond to the line items in Table 3.5-1 of the September 2005 Revision 1 SRP-LR document; therefore, in many cases, they do not match the line items in Table 3.5.1 of the OCGS LRA. The SRP-LR line item number is denoted parenthetically in the column 1 entry. Also, line items that are applicable only to PWR plants are not included in this table; therefore, certain SRP-LR line item numbers do not appear in this table.

Table 3.5-1 Staff Evaluation for Containment, Structures, Component Supports, and Piping and Component Insulation in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
BWR Concrete and Steel (Mark I, II, and III) Containments				
Concrete elements: walls, dome, basemat, ring girder, buttresses, containment (as applicable). (Item 3.5.1-1)	Aging of accessible and inaccessible concrete areas due to aggressive chemical attack, and corrosion of embedded steel	ISI (IWL) and for inaccessible concrete, an examination of representative samples of below-grade concrete, and periodic monitoring of groundwater if environment is non-aggressive. A plant specific program is to be evaluated if environment is aggressive.	Not Applicable	Not Applicable; Steel containment (See Audit Report Section 3.5.2.2.1.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Concrete elements; All (Item 3.5.1-2)	Cracks and distortion due to increased stress levels from settlement	Structures Monitoring Program. If a de-watering system is relied upon for control of settlement, then licensee to ensure proper functioning of the de-watering system through the period of extended operation.	Not Applicable	Not Applicable; Steel containment (See Audit Report Section 3.5.2.2.1.2)
Concrete elements: foundation, sub-foundation (Item 3.5.1-3)	Reduction in foundation strength, cracking, differential settlement due to erosion of porous concrete subfoundation	Structures Monitoring Program If a de-watering system is relied upon to control erosion of cement from porous concrete subfoundations, then licensee to ensure proper functioning of the de-watering system through the period of extended operation.	Not Applicable	Not Applicable; Steel containment (See Audit Report Section 3.5.2.2.1.2)
Concrete elements: dome, wall, basemat, ring girder, buttresses, containment, concrete fill-in annulus (as applicable) (Item 3.5.1-4)	Reduction of strength and modulus of concrete due to elevated temperature	A plant-specific AMP is to be evaluated	Not Applicable	Not Applicable; Steel containment (See Audit Report Section 3.5.2.2.1.3)
Steel elements: Drywell; torus; drywell head; embedded shell and sand pocket regions; drywell support skirt; torus ring girder; downcomers; liner plate, ECCS suction header, support skirt, region shielded by diaphragm floor,	Loss of material due to general, pitting and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	ISI (IWE) (B.1.27) and 10 CFR Part 50, Appendix J (B.1.29); Protective Coatings (B.1.33)	Consistent with GALL, which recommends further evaluation (See Audit Report Section 3.5.2.2.1.4)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
suppression chamber (as applicable) (Item 3.5.1-5)				
Steel elements: steel liner, liner anchors, integral attachments (Item 3.5.1-6)	Loss of material due to general, pitting and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	ISI (IWE) (B.1.27) and 10 CFR Part 50, Appendix J (B.1.29)	Consistent with GALL, which recommends further evaluation (See Audit Report Section 3.5.2.2.1.4)
Prestressed containment tendons (Item 3.5.1-7)	Loss of prestress due to relaxation, shrinkage, creep, and elevated temperature	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Not Applicable	Not Applicable; Steel containment (See Audit Report Section 3.5.2.2.1.5)
Steel and stainless steel elements: vent line, vent header, vent line bellows; downcomers; (Item 3.5.1-8)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	Evaluated by DE (See Audit Report Section 3.5.2.2.1.6)
Steel, stainless steel elements, dissimilar metal welds: penetration sleeves, penetration bellows; suppression pool shell, unbraced downcomers (Item 3.5.1-9)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	Evaluated by DE (See Audit Report Section 3.5.2.2.1.6)
Stainless steel penetration sleeves, penetration bellows, dissimilar metal welds (Item 3.5.1-10)	Cracking due to stress corrosion cracking	ISI (IWE) and 10 CFR Part 50, Appendix J, and additional appropriate examinations/ evaluations for bellows assemblies and dissimilar metal welds.	ISI (IWE) (B.1.27) and 10 CFR Part 50, Appendix J (B.1.29)	Consistent with GALL, which recommends further evaluation (See Audit Report Section 3.5.2.2.1.7)
Stainless steel vent line bellows, (Item 3.5.1-11)	Cracking due to stress corrosion cracking	ISI (IWE) and 10 CFR Part 50, Appendix J, and additional appropriate examination/ evaluation for bellows assemblies and dissimilar metal	ISI (IWE) (B.1.27) and 10 CFR Part 50, Appendix J (B.1.29)	Consistent with GALL, which recommends further evaluation (See Audit Report Section 3.5.2.2.1.7)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
		welds.		
Steel, stainless steel elements, dissimilar metal welds: penetration sleeves, penetration bellows; suppression pool shell, unbraced downcomers (Item 3.5.1-12)	Cracking due to cyclic loading	ISI (IWE) and 10 CFR Part 50, Appendix J, and supplemented to detect fine cracks	TLAA (CLB fatigue analysis exists); covered by Item 3.5.1-9	Evaluated by DE (See Audit Report Section 3.5.2.2.1.8)
Steel, stainless steel elements, dissimilar metal welds: torus; vent line; vent header; vent line bellows; downcomers (Item 3.5.1-13)	Cracking due to cyclic loading	ISI (IWE) and 10 CFR Part 50, Appendix J, and supplemented to detect fine cracks	TLAA (CLB fatigue analysis exists); covered by Item 3.5.1-8	Evaluated by DE (See Audit Report Section 3.5.2.2.1.8)
Concrete elements: dome, wall, basemat ring girder, buttresses, containment (as applicable) (Item 3.5.1-14)	Loss of material (Scaling, cracking, and spalling) due to freeze-thaw	ISI (IWL). Evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index > 100 day-inch/yr) (NUREG-1557).	Not Applicable	Not Applicable; Steel containment (See Audit Report Section 3.5.2.2.1.9)
Concrete elements: walls, dome, basemat, ring girder, buttresses, containment, concrete fill-in annulus (as applicable). (Item 3.5.1-15)	Cracking due to expansion and reaction with aggregate; increase in porosity, permeability due to leaching of calcium hydroxide	ISI (IWL) for accessible areas. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R.	Not Applicable	Not Applicable; Steel containment (See Audit Report Section 3.5.2.2.1.10)
Seals, gaskets, and moisture barriers (Item 3.5.1-16)	Loss of sealing and leakage through containment due to deterioration of joint seals, gaskets, and moisture barriers (caulking, flashing, and other sealants)	ISI (IWE) and 10 CFR Part 50, Appendix J	ISI (IWE) (B.1.27) and 10 CFR Part 50, Appendix J (B.1.29)	Consistent with GALL (See Audit Report Section 3.5.2.1)
Personnel airlock, equipment hatch and CRD hatch	Loss of leak tightness in closed position due to	10 CFR Part 50, Appendix J and Plant Technical	10 CFR Part 50, Appendix J (B.1.29) and Plant Technical	Consistent with GALL (See Audit Report Section

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
locks, hinges, and closure mechanisms (Item 3.5.1-17)	mechanical wear of locks, hinges and closure mechanisms	Specifications	Specifications	3.5.2.1)
Steel penetration sleeves and dissimilar metal welds; personnel airlock, equipment hatch and CRD hatch (Item 3.5.1-18)	Loss of material due to general, pitting, and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	ISI (IWE) (B.1.27) and 10 CFR Part 50, Appendix J (B.1.29)	Consistent with GALL (See Audit Report Section 3.5.2.1)
Steel elements: stainless steel suppression chamber shell (inner surface) (Item 3.5.1-19)	Cracking due to stress corrosion cracking	ISI (IWE) and 10 CFR Part 50, Appendix J	Not applicable	Not applicable; carbon steel suppression chamber
Steel elements: suppression chamber liner (interior surface) (Item 3.5.1-20)	Loss of material due to general, pitting, and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	Not applicable	Not applicable; carbon steel suppression chamber; no liner
Steel elements: drywell head and downcomer pipes (Item 3.5.1-21)	Fretting or lock up due to mechanical wear	ISI (IWE)	ISI (IWE) (B.1.27)	Consistent with GALL (See Audit Report Section 3.5.2.1)
Prestressed containment: tendons and anchorage components (Item 3.5.1-22)	Loss of material due to corrosion	ISI (IWL)	Not Applicable	Not Applicable; Steel containment
Safety-Related and Other Structures; and Component Supports				
All Groups except Group 6: interior and above grade exterior concrete (Item 3.5.1-23)	Cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring Program	Structures Monitoring Program (B.1.31)	Consistent with GALL (See Audit Report Section 3.5.2.2.2.1)
All Groups except Group 6: interior and above grade exterior concrete (Item 3.5.1-24)	Increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring Program	Structures Monitoring Program (B.1.31)	Consistent with GALL (See Audit Report Section 3.5.2.2.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
All Groups except Group 6: steel components: all structural steel (Item 3.5.1-25)	Loss of material due to corrosion	Structures Monitoring Program. If protective coatings are relied upon to manage the effects of aging, the structures monitoring program is to include provisions to address protective coating monitoring and maintenance.	Structures Monitoring Program (B.1.31)	Consistent with GALL (See Audit Report Section 3.5.2.2.2.1)
All Groups except Group 6: accessible and inaccessible concrete: foundation (Item 3.5.1-26)	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring Program. Evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index > 100 day-inch/yr) (NUREG-1557).	Structures Monitoring Program (B.1.31)	Consistent with GALL, which recommends further evaluation (See Audit Report Section 3.5.2.2.2.2.1)
All Groups except Group 6: accessible and inaccessible interior/exterior concrete (Item 3.5.1-27)	Cracking due to expansion due to reaction with aggregates	Structures Monitoring Program. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R-77.	Structures Monitoring Program (B.1.31)	Consistent with GALL, which recommends further evaluation (See Audit Report Section 3.5.2.2.2.2.2)
Groups 1-3, 5-9: All (Item 3.5.1-28)	Cracks and distortion due to increased stress levels from settlement	Structures Monitoring Program. If a de-watering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Structures Monitoring Program (B.1.31)	Consistent with GALL, which recommends further evaluation (See Audit Report Section 3.5.2.2.2.2.3)
Groups 1-3, 5-9: foundation	Reduction in foundation strength,	Structures Monitoring	Not applicable	Not applicable; no porous concrete

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
(Item 3.5.1-29)	cracking, differential settlement due to erosion of porous concrete subfoundation	Program. If a de-watering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.		subfoundation or de-watering system (See Audit Report Section 3.5.2.2.2.2.3)
Group 4: Radial beam seats in BWR drywell; RPV support shoes for PWR with nozzle supports; Steam generator supports (Item 3.5.1-30)	Lock-up due to wear	ISI (IWF) or Structures Monitoring Program	Structures Monitoring Program (B.1.31)	Consistent with GALL. (See Audit Report Section 3.5.2.1.3)
Groups 1-3, 5, 7-9: below-grade concrete components, such as exterior walls below grade and foundation (Item 3.5.1-31)	Increase in porosity and permeability, cracking, loss of material (spalling, scaling)/aggressive chemical attack; Cracking, loss of bond, and loss of material (spalling, scaling)/corrosion of embedded steel	Structures monitoring Program; Examination of representative samples of below-grade concrete, and periodic monitoring of groundwater, if the environment is non-aggressive. A plant specific program is to be evaluated if environment is aggressive.	Structures Monitoring Program (B.1.31); Examination of representative samples of below-grade concrete, and periodic monitoring of groundwater (non-aggressive environment).	Consistent with GALL, which recommends further evaluation (See Audit Report Section 3.5.2.2.2.2.4)
Groups 1-3, 5, 7-9: exterior above and below grade reinforced concrete foundations (Item 3.5.1-32)	Increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide	Structures Monitoring Program for accessible areas. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R-77.	Structures Monitoring Program (B.1.31)	Consistent with GALL, which recommends further evaluation (See Audit Report Section 3.5.2.2.2.2.5)
Groups 1-5: concrete (Item 3.5.1-33)	Reduction of strength and modulus due to elevated	A plant-specific AMP is to be evaluated	Structures Monitoring Program (B.1.31) with a 2-year inspection	Consistent with GALL, which recommends further evaluation

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
	temperature		frequency and a quantitative criterion for crack width	(See Audit Report Section 3.5.2.2.2.3)
Group 6: Concrete; all (Item 3.5.1-34)	Increase in porosity and permeability, cracking, loss of material due to aggressive chemical attack; cracking, loss of bond, loss of material due to corrosion of embedded steel	Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance programs and for inaccessible concrete, an examination of representative samples of below-grade concrete, and periodic monitoring of groundwater, if the environment is non-aggressive. A plant specific program is to be evaluated if environment is aggressive.	Inspection of Water-Control Structures (B.1.32)	Consistent with GALL, which recommends further evaluation (See Audit Report Section 3.5.2.2.2.4.1)
Group 6: exterior above and below grade concrete foundation (Item 3.5.1-35)	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance programs. Evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index > 100 day-inch/yr) (NUREG-1557).	Inspection of Water-Control Structures (B.1.32)	Consistent with GALL, which recommends further evaluation (See Audit Report Section 3.5.2.2.2.4.2)
Group 6: all accessible/ inaccessible reinforced concrete (Item 3.5.1-36)	Cracking due to expansion/reaction with aggregates	Accessible areas: Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections	Inspection of Water-Control Structures (B.1.32)	Consistent with GALL, which recommends further evaluation (See Audit Report Section 3.5.2.2.2.4.3)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
		and maintenance programs. None for inaccessible areas if concrete was constructed in accordance with recommendations in ACI 201.2R-77.		
Group 6: exterior above and below grade reinforced concrete foundation interior slab (Item 3.5.1-37)	Increase in porosity and permeability, loss of strength due to leaching of calcium hydroxide	For accessible areas, Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance programs. None for inaccessible areas if concrete was constructed in accordance with recommendations in ACI 201.2R-77.	Inspection of Water-Control Structures (B.1.32)	Consistent with GALL, which recommends further evaluation (See Audit Report Section 3.5.2.2.2.4.3)
Groups 7, 8: Tank liners (Item 3.5.1-38)	Cracking due to stress corrosion cracking; loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated	Not Applicable	Not applicable; The only stainless steel lined concrete tank at Oyster Creek is the spent fuel pool skimmer surge tank. Aging effects of the stainless steel tank liner are evaluated with the mechanical auxiliary systems. (See Audit Report Section 3.5.2.2.2.5)
Support members; welds; bolted connections; support anchorage to building structure (Item 3.5.1-39)	Loss of material due to general and pitting corrosion	Structures Monitoring Program	Structures Monitoring Program (B.1.31)	Consistent with GALL (See Audit Report Section 3.5.2.2.2.6)
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates (Item 3.5.1-40)	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging	Structures Monitoring Program	Structures Monitoring Program (B.1.31)	Consistent with GALL (See Audit Report Section 3.5.2.2.2.6)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
	mechanisms			
Vibration isolation elements (Item 3.5.1-41)	Reduction or loss of isolation function/radiation hardening, temperature, humidity, sustained vibratory loading	Structures Monitoring Program	Structures Monitoring Program (B.1.31)	Consistent with GALL (See Audit Report Section 3.5.2.2.2.6)
Groups B1.1, B1.2, and B1.3: support members: anchor bolts, welds (Item 3.5.1-42)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Not applicable; no CLB fatigue analyses)	Not applicable; no CLB fatigue analyses (See Audit Report Section 3.5.2.2.2.7)
Groups 1-3, 5, 6: all masonry block walls (Item 3.5.1-43)	Cracking due to restraint shrinkage, creep, and aggressive environment	Masonry Wall Program	Masonry Wall Program (B.1.30)	Consistent with GALL (See Audit Report Section 3.5.2.1)
Group 6 elastomer seals, gaskets, and moisture barriers (Item 3.5.1-44)	Loss of sealing due to deterioration of seals, gaskets, and moisture barriers (caulking, flashing, and other sealants)	Structures Monitoring Program	Structures Monitoring Program (B.1.31)	Consistent with GALL (See Audit Report Section 3.5.2.12)
Group 6: exterior above and below grade concrete foundation; interior slab (Item 3.5.1-45)	Loss of material due to abrasion, cavitation	Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance	Inspection of Water-Control Structures (B.1.32)	Consistent with GALL (See Audit Report Section 3.5.2.1)
Group 5: Fuel pool liners (Item 3.5.1-46)	Cracking due to stress corrosion cracking; loss of material due to pitting and crevice corrosion	Water Chemistry and monitoring of spent fuel pool water level in accordance with technical specifications and leakage from the leak chase channels.	Water Chemistry (B.1.2) and monitoring of spent fuel pool water level in accordance with technical specifications	Consistent with GALL (See Audit Report Section 3.5.2.1)
Group 6: all metal structural members (Item 3.5.1-47)	Loss of material due to general (steel only), pitting and crevice corrosion	Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance. If protective coatings are relied upon to	Inspection of Water-Control Structures (B.1.32)	Consistent with GALL (See Audit Report Section 3.5.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
		manage aging, protective coating monitoring and maintenance provisions should be included.		
Group 6: earthen water control structures – dams, embankments, reservoirs, channels, canals, and ponds (Item 3.5.1-48)	Loss of material, loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, Seepage	Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance programs	Inspection of Water-Control Structures (B.1.31)	Consistent with GALL (See Audit Report Section 3.5.2.1)
Support members; welds; bolted connections; support anchorage to building structure (Item 3.5.1-49)	Loss of material/ general, pitting, and crevice corrosion	Water Chemistry and ISI (IWF)	Water Chemistry and ISI (IWF) for Treated Water Environment	Consistent with GALL (See Audit Report Section 3.5.2.1)
Groups B2, and B4: galvanized steel, aluminum, stainless steel support members; welds; bolted connections; support anchorage to building structure (Item 3.5.1-50)	Loss of material due to pitting and crevice corrosion	Structures Monitoring Program	Structures Monitoring Program	Consistent with GALL (See Audit Report Section 3.5.2.1)
Group B1.1: high strength low-alloy bolts (Item 3.5.1-51)	Cracking due to stress corrosion cracking; loss of material due to general corrosion	Bolting Integrity	Not applicable	Not applicable; no high strength low-alloy bolts used in Group B1.1 supports
Groups B2, and B4: sliding support bearings and sliding support surfaces (Item 3.5.1-52)	Loss of mechanical function due to corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads	Structures Monitoring Program	Structures Monitoring Program (B.1.31)	Consistent with GALL (See Audit Report Section 3.5.2.1)
Groups B1.1, B1.2, and B1.3: support members: welds; bolted connections; support anchorage to building structure (Item 3.5.1-53)	Loss of material due to general and pitting corrosion	ISI (IWF)	ISI (IWF) (B.1.28)	Consistent with GALL (See Audit Report Section 3.5.2.1)
Groups B1.1, B1.2, and B1.3: Constant	Loss of mechanical function due to	ISI (IWF)	ISI (IWF) (B.1.28)	Consistent with GALL (See Audit

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
and variable load spring hangers; guides; stops; (Item 3.5.1-54)	corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads			Report Section 3.5.2.1)
Groups B1.1, B1.2, and B1.3: Sliding surfaces (Item 3.5.1-56)	Loss of mechanical function due to corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads	ISI (IWF)	ISI (IWF) (B.1.28)	Consistent with GALL (See Audit Report Section 3.5.2.1)
Groups B1.1, B1.2, and B1.3: Vibration isolation elements (Item 3.5.1-57)	Reduction or loss of isolation function/ radiation hardening, temperature, humidity, sustained vibratory loading	ISI (IWF)	ISI (IWF) (B.1.28)	Consistent with GALL (See Audit Report Section 3.5.2.1)
Galvanized steel and aluminum support members; welds; bolted connections; support anchorage to building structure exposed to air – indoor uncontrolled (Item 3.5.1-58)	None	None	None	Consistent with GALL (See Audit Report Section 3.5.2.1)
Stainless steel support members; welds; bolted connections; support anchorage to building structure (Item 3.5.1-59)	None	None	None	Consistent with GALL (See Audit Report Section 3.5.2.1)

3.5.2.1 *AMR Results That Are Consistent with The GALL Report*

Summary of Information in the Application

For aging management evaluations that the applicant states are consistent with the GALL Report, the project team conducted its audit and review to determine if the applicant's reference to the GALL Report in the OCGS LRA is acceptable.

In OCGS LRA Section 3.5.1.2.1, the applicant identified the materials, environments, and aging effects requiring management. The applicant identified the following programs that manage the aging effects related to the primary containment, reactor building, chlorination facility, condensate transfer building, dilution structure, emergency diesel generator building, exhaust tunnel, fire pond dam, fire pumphouses, heating boiler house, intake structure and canal, miscellaneous yard structures, new radwaste building, office building, oyster creek substation, turbine building, ventilation stack, component supports commodity group, piping and component insulation commodity group components and component groups:

- Water Chemistry Program (B.1.2)
- ASME Section XI, Subsection IWE Program (B.1.27)
- ASME Section XI, Subsection IWF Program (B.1.28)
- 10 CFR Part 50, Appendix J Program (B.1.29)
- Masonry Wall Program (B.1.30)
- Structures Monitoring Program (B.1.31)
- RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants Program (B.1.32)
- Protective Coating Monitoring and Maintenance Program (B.1.33)

Project Team Evaluation

The project team reviewed its assigned OCGS LRA AMR line-items to determine that the applicant (1) provides a brief description of the system, components, materials, and environment; (2) states that the applicable aging effects have been reviewed and are evaluated in the GALL Report; and (3) identifies those aging effects for the primary containment, reactor building, chlorination facility, condensate transfer building, dilution structure, emergency diesel generator building, exhaust tunnel, fire pond dam, fire pumphouses, heating boiler house, intake structure and canal, miscellaneous yard structures, new radwaste building, office building, oyster creek substation, turbine building, ventilation stack, component supports commodity group, piping and component insulation commodity group components that are subject to an AMR.

Based on its review of the AMR results for which the applicant claimed consistency with the GALL Report, the project team asked the applicant for several clarifications, and also for additional supporting information.

3.5.2.1.1 Stress Corrosion Cracking of High Strength Low Alloy Bolting Materials (Item 3.5.1-51)

The project team asked the applicant to provide additional information to ensure that this aging effect is not applicable to OCGS. The applicant provided data on the material types used in structural applications, and their as-received yield strengths. One recent use of A-490 bolts was identified for a crane support. However, since the bolt is not pre-loaded in this application, an important pre-condition for SCC does not exist.

Based on a review of this data, the project team determined that no high strength low alloy bolting materials susceptible to SCC are used in structural applications at OCGS, and found the applicant’s AMR result to be acceptable.

3.5.2.1.2 Degradation of Group 6 Elastomer Seals, Gaskets, and Moisture Barriers (Item 3.5.1-44)

The project team asked the applicant to clarify its AMR result. The applicant stated that this aging effect was referenced to Table 1 Item 3.3.1-46, because Item 3.5.1-44 did not exist in the January 2005 draft GALL update. It was added in the September 2005 GALLRev. 1. The applicant credits the structures monitoring program, which is consistent with the GALL Report.

The project team reviewed the corresponding Table 2 entries, and found the applicant's AMR result for this aging effect to be consistent with the GALL Report.

3.5.2.1.3 Lock-up Due to Wear of Radial Beam Seats in BWR Drywell (Item 3.5.1-30)

The applicant identified this as not applicable to OCGS in the LRA, because Lubrite plates are not used. The project team asked the applicant to provide more information about the design of the radial beam seats and how free movement is achieved. In response, the applicant described the two sets of radial beams at El. 44'-3" and 23'-6", and identified that Lubrite plates are used on support brackets at the 23'-6" elevation. The applicant further stated that the radial beams and support brackets are inspected for loss of material under the structures monitoring program, but based on industry operating history, Lubrite does not require aging management for lock-up due to wear. However, the support brackets which incorporate the use of Lubrite are monitored under the structures monitoring program.

The project team determined that the existing commitment to monitor the radial beams and support brackets under the structures monitoring program is sufficient to identify any degradation of the Lubrite® plates' intended function to allow free movement. The applicant's AMR result for this aging effect is consistent with the intent of the GALL Report, and is acceptable.

3.5.2.1.4 No Aging Effect for Steel (All Types) and Aluminum in a ?Concrete" Environment

The applicant referenced a Table 1 item under auxiliary systems in the Table 2s for structures, and claimed consistency with GALL. The project team asked the applicant to describe the plant-specific operating experience for structural applications of steel (all types) and aluminum in a concrete environment. The applicant indicated that there was no history of degradation for structural applications of steel (all types) and aluminum embedded in concrete, as long as no concrete degradation occurred that allowed exposure to air and water. The applicant further stated that it will evaluate inaccessible areas (embedments) if there are indications in an accessible area that may be indicative of degradation in the inaccessible area.

The project team determined that the applicant's AMR result for steel (all types) and aluminum in a concrete environment is consistent with the recommendations in the GALL Report, and found it to be acceptable.

3.5.2.1.5 No Aging Effect for Stainless and Galvanized Steel and Aluminum in a ?Indoor-Air" or ?Containment-Atmosphere" Environment

The applicant referenced Table 1 items under auxiliary systems in the Table 2s for structures, and claimed consistency with GALL. The project team asked the applicant to describe the plant-specific operating experience for structural applications of stainless and galvanized steel and aluminum in a indoor-air or containment-atmosphere environment. The applicant indicated that there was no history of degradation for structural applications of stainless and galvanized steel and aluminum in a indoor-air or containment-atmosphere environment.

The project team determined that the applicant's AMR result for stainless and galvanized steel and aluminum in an indoor-air or containment-atmosphere environment is consistent with the recommendations in the GALL Report, and found it to be acceptable.

3.5.2.1.6 Loss of Preload in Structural Bolting

The applicant referenced Table 1 items under auxiliary systems in the Table 2s for structures, credited the structures monitoring program, and claimed consistency with GALL. The project team asked the applicant to describe how loss of preload is managed by the structures monitoring program for structural bolting. The applicant indicated that structural bolting applications at OCGS do not require specific predetermined bolting preload to assure the intended function. Typical methods, such as turn-of-the-nut, are used to ensure adequate joint tightness. Loss of preload in this context refers to loss of joint integrity due to loose or missing bolts and nuts. This aging effect is managed by visual inspection for loose or missing nuts and bolts.

The project team determined that the applicant's AMR result for loss of preload in structural bolting is consistent with the recommendations in the GALL Report, and found it to be acceptable.

3.5.2.1.7 AMR Result for Class MC Pressure Retaining Bolting

The applicant referenced a Table 1 item under Engineered Safety Features in LRA Table 3.5.2.1.1, credited the IWE and Appendix J programs, and claimed consistency with GALL. The project team noted that there is no comparable Table 1 item under structures. The project team asked the applicant to provide additional information about its AMR result for Class MC pressure retaining bolting. The applicant indicated that IWE is credited for managing loss of material and Appendiix J leak rate testing is credited for managing leak-tightness of the containment, including loss of preload in the Class MC pressure retaining bolting.

The project team determined that the applicant's AMR result for Class MC pressure retaining bolting is consistent with the recommendations in the GALL Report, and found it to be acceptable.

3.5.2.1.8 Loss of Mechanical Function for Stainless and Galvanized Steel and Aluminum ASME Class 1,2,3 and MC Supports (Item 3.5.1-58, Item 3.5.1-59, LRA Table 3.5.2.1.18)

The project team noted that ?loss of mechanical function" was not identified in LRA Table 3.5.2.18 as an applicable aging effect, in need of aging management, for stainless and galvanized steel and aluminum ASME Class 1,2,3 and MC supports. The project team also noted that SRP-LR Table 1 items 3.5.1-58 and 3.5.1-59 do not list the specific aging effects addressed, for which aging management is not required. The project team asked the applicant to explain why loss of mechanical function is not an applicable aging effect for these materials. The applicant stated that all special OCGS ASME Class 1,2,3 and MC supports, for which loss of mechanical function is an applicable aging effect (e.g., constant and variable load spring hangers), are fabricated from carbon and low-alloy steel.

The project team determined that the applicant's AMR result for stainless and galvanized steel and aluminum ASME Class 1,2,3 and MC supports is consistent with the GALL Report.

Conclusion

The project team has evaluated the applicant's claim of consistency with the GALL Report. The project team also has reviewed information pertaining to the applicant's consideration of recent and proposals for managing associated aging effects. On the basis of its review, the project team found that the AMR results, which the applicant claimed to be consistent with the GALL Report, are consistent with the AMRs in the GALL Report.

3.5.2.2 *AMR Results For Which Further Evaluation Is Recommended By The GALL Report*

Summary of Information in the Application

In OCGS LRA Section 3.5.2.2, the applicant provided further evaluation of aging management, as recommended by the GALL Report, for the aging effects related to the primary containment, reactor building, chlorination facility, condensate transfer building, dilution structure, emergency diesel generator building, exhaust tunnel, fire pond dam, fire pumphouses, heating boiler house, intake structure and canal, miscellaneous yard structures, new radwaste building, office building, oyster creek substation, turbine building, ventilation stack, component supports commodity group, piping and component insulation commodity group components and component groups. The applicant also provided information concerning how it will manage the related aging effects.

Project Team Evaluation

For some AMR line-items assigned to the project team in the OCGS LRA Tables 3.5.1, the GALL Report recommends further evaluation. When further evaluation is recommended, the project team reviewed these further evaluations provided in OCGS LRA Section 3.5.2.2 against the criteria provided in the SRP-LR Section 3.5.2.2. The project team's assessments of these evaluations are documented in this section. These assessments are applicable to each Table 2 AMR line-item in Section 3.5 citing the item in Table 1.

3.5.2.2.1 PWR and BWR Containments

3.5.2.2.1.1 Aging of Inaccessible Concrete Areas

In Section 3.5.2.2.1.1 of the OCGS LRA, the applicant stated that aging of inaccessible areas of concrete containments is not applicable since Oyster Creek has a Mark I steel containment. The project team concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek has a Mark I steel containment.

3.5.2.2.1.2 Cracks and Distortion Due to Increased Stress Levels from Settlement; Reduction of Foundation Strength, Cracking and Differential Settlement Due to Erosion of Porous Concrete Subfoundations, If Not Covered by Structures Monitoring Program

In Section 3.5.2.2.1.2 of the OCGS LRA, the applicant stated that cracks and distortion of concrete subfoundations are not applicable since Oyster Creek has a Mark I steel containment. The project team concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek has a Mark I steel containment.

3.5.2.2.1.3 Reduction of Strength and Modulus of Concrete Structures Due to Elevated Temperature

The project team reviewed OCGS LRA Section 3.5.2.2.1.3 against the criteria in SRP-LR Section 3.5.2.2.1.3.

SRP-LR Section 3.5.2.2.1.3 stated that reduction of strength and modulus of concrete due to elevated temperatures could occur in PWR and BWR concrete and steel containments. The implementation of 10 CFR 50.55a and ASME Section XI, Subsection IWL would not be able to identify the reduction of strength and modulus of concrete due to elevated temperature. Subsection CC-3400 of ASME Section III, Division 2, specifies the concrete temperature limits for normal operation or any other long-term period. The GALL Report recommends further evaluation of a plant-specific aging management program if any portion of the concrete containment components exceeds specified temperature limits, i.e., general area temperature greater than 66˚C (150˚F) and local area temperature greater than 93˚C (200˚F).

In the OCGS LRA Section 3.5.2.2.1.3, the applicant addressed reduction of strength and modulus of concrete due to elevated temperatures. The OCGS LRA stated that the normal operating temperature inside the Oyster Creek primary containment drywell varies from 139˚F (at elev. 55') to 256˚F (at elev. 95'). The containment structure is a BWR Mark I steel containment, which is not affected by general area temperature of 150˚F and local area temperature of 200˚F. Concrete for the reactor pedestal, and the drywell floor slab (fill slab) are located below elev. 55' and are not exposed to the elevated temperature. The biological shield wall extends from elev. 37'-3" to elev. 82'-2" and is exposed to a temperature range of 139˚F – 184˚F. The wall is a composite steel-concrete cylinder surrounding the reactor vessel. It is framed with 27 in. deep wide flange columns covered with steel plate on both sides. The area between the plates is filled with high density concrete to satisfy the shielding requirements. The steel columns provide the intended structural support function and the encased high density concrete provides shielding requirements. The encased concrete is not accessible for inspection.

The elevated drywell temperature concern was evaluated as a part of the Integrated Plant Assessment Systematic Evaluation Program (SEP Topic III-7.B). The evaluation concluded that the temperature would not adversely affect the structural and shielding functions of the wall.

The elevated drywell temperature was also identified as a concern for the reactor building drywell shield wall. Further evaluation for this wall is discussed in subsection 3.5.2.2.2, item (8).

The project team concurs with the applicant's further evaluation because the existing elevated temperature condition in the drywell will not impair the intended functions of the steel containment shell or the shielding concrete of the biological shield wall.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.5.2.2.1.3 for further evaluation.

3.5.2.2.1.4 <u>Loss of Material Due to General, Pitting and Crevice Corrosion</u>

The project team reviewed OCGS LRA Section 3.5.2.2.1.4 against the criteria in SRP-LR Section 3.5.2.2.1.4.

SRP-LR Section 3.5.2.2.1.4 stated that loss of material due to general, pitting and crevice corrosion could occur in steel elements of accessible and inaccessible areas for all types of PWR and BWR containments. The existing program relies on ASME Section XI, Subsection IWE, and 10 CFR Part 50, Appendix J, to manage this aging effect. The GALL Report recommends further evaluation of plant-specific programs to manage this aging effect for inaccessible areas if corrosion is significant.

In the OCGS LRA Section 3.5.2.2.1.4, the applicant addressed loss of material of steel elements due to general, pitting and crevice corrosion. The OCGS LRA stated that at Oyster Creek, the potential for loss of material, due to corrosion, in inaccessible areas of the containment drywell shell was first recognized in 1980 when water was discovered coming from the sand bed region drains. Corrosion was later confirmed by ultrasonic thickness (UT) measurements taken during the 1986 refueling outage. As a result, several corrective actions were initiated to determine the extent of corrosion, evaluate the integrity of the drywell, mitigate accelerated corrosion, and monitor the condition of containment surfaces. The corrective actions include extensive UT measurements of the drywell shell thickness, removal of the sand in the sand bed region, cleaning and coating exterior surfaces in areas where sand was removed, and an engineering evaluation to confirm the drywell structural integrity. A corrosion monitoring program was established, in 1987, for the drywell shell above the sand bed region to ensure that the containment vessel is capable of performing its intended functions. Elements of the program have been incorporated into the ASME Section XI, Subsection IWE (B.1.27) and provide for:

- Periodic UT inspections of the shell thickness at critical locations,
- Calculations which establish conservative corrosion rates,
- Projections of the shell thickness based on the conservative corrosion rates, and
- Demonstration that the minimum required shell thickness is in accordance with ASME code.

Additionally, the NRC was notified of this potential generic issue that later became the subject of NRC IN 86-99 and GL 87-05.

The applicant provided the following summary of the operating experience, monitoring activities, and corrective actions taken to ensure that the primary containment will perform its intended functions:

Drywell Shell in the Sand Bed Region:

The drywell shell is fabricated from ASTM A-212-61T Gr. B steel plate. The shell was coated on the inside surface with an inorganic zinc (Carboline carbozinc 11) and on the outside surface with ?Red Lead" primer identified as TT-P-86C Type I. The red lead coating covered the entire exterior of the vessel from elevation 8' 11.25" (Fill slab level) to elevation 94' (below drywell flange).

The sand bed region was filled with dry sand as specified by ASTM 633. Leakage of water from the sand bed drains was observed during the 1980 and 1983 refueling outages. A series of investigations were performed to identify the source of the water and its leak path. The results concluded that the source of water was from the refueling cavity, which is flooded during refueling outages.

As a result of the presence of water in the sand bed region, extensive UT thickness measurements (about 1000) of the drywell shell were taken to determine if degradation was occurring. These measurements corresponded to known water leaks and indicated that wall thinning had occurred in this region.

Because of reduced thickness readings, additional thickness measurements were obtained to determine the vertical profile of the thinning. A trench was excavated inside the drywell, in the concrete floor, in the area where thinning at the floor level was most severe. Measurements taken from the excavated trench indicated that thinning of the embedded shell in concrete were no more severe than those taken at the floor level and became less severe at the lower portions of the sand bed region. Conversely, measurements taken in areas where thinning was not identified at the floor level showed no indication of significant thinning in the embedded shell. Aside from UT thickness measurements performed by plant staff, independent analysis was performed by the EPRI NDE Center and the GE Ultra Image III ?C" scan topographical mapping system. The independent tests confirmed the UT results. The GE Ultra Image results were used as baseline profile to track continued corrosion.

To validate UT measurements and characterize the form of damage and its cause (i.e., due to the presence of contaminants, microbiological species, or both) core samples of the drywell shell were obtained at seven locations. The core samples validated the UT measurements and confirmed that the corrosion of the drywell is due to the presence of oxygenated wet sand and exacerbated by the presence of chloride and sulfate in the sand bed region. A contaminate concentrating mechanism due to alternate wetting and drying of the sand may have also contributed to the corrosion phenomenon. It was therefore concluded that the optimum method for mitigating the corrosion is by (1) removal of the sand to break up the galvanic cell, (2) removal of the corrosion product from the shell and (3) application of a protective coating.

Removal of sand was initiated during 1988 by removing sheet metal from around the vent headers to provide access to the sand bed from the Torus room. During operating cycle 13 some sand was removed and access holes were cut into the sand bed region through the shield wall. The work was finished in December 1992 . After sand removal, the concrete surface below the sand was found to be unfinished with improper provisions for water drainage. Corrective actions taken in this region during 1992 included; (1) cleaning of loose rust from the drywell shell, followed by application of epoxy coating and (2) removing the loose debris from the concrete floor followed by rebuilding and reshaping the floor with epoxy to allow drainage of any water that may leak into the region. UT measurements taken from the outside after cleaning verified loss of material projections that had been made based on measurements taken from the inside of the drywell. There were, however, some areas thinner than projected; but in all cases engineering analysis determined that the drywell shell thickness satisfied ASME code requirements. The Protective Coating Monitoring and Maintenance Program was revised to include monitoring of the coatings of exterior surfaces of the drywell in the sand bed region.

The coated surfaces of the former sand bed region were subsequently inspected during refueling outages of 1994, 1996, 2000, and 2004. The inspections showed no coating failure or signs of deterioration. It is therefore concluded that corrosion in the sand bed region has been arrested and no further loss of material is expected. Monitoring of the coating in accordance with the Protective Coating Monitoring and Maintenance Program, will continue to ensure that the containment drywell shell maintains its intended function during the period of extended operation.

<u>Drywell Shell Above Sand Bed Region</u>:

The UT investigation phase (1986 through 1991) also identified loss of material, due to corrosion, in the upper regions of the drywell shell. These regions were handled separately from the sand bed region because of the significant difference in corrosion rate and physical difference in design. Corrective action for these regions involved providing a corrosion allowance by demonstrating, through analysis, that the original drywell design pressure was conservative. Amendment 165 to the Oyster Creek Technical Specifications reduced the drywell design pressure from 62 psig to 44 psig. The new design pressure coupled with measures to prevent water intrusion into the gap between the drywell shell and the concrete will allow the upper portion of the drywell to meet ASME code requirements.

Originally, the knowledge of the extent of corrosion was based on UT measurements going completely around the inside of the drywell at several elevations. At each elevation, a belt-line sweep was used with readings taken on as little as 1" centers wherever thickness changed between successive nominal 6" centers. Six-by-six grids that exhibited the worst metal loss around each elevation were established using this approach and included in the Drywell Corrosion Inspection Program.

As experience increased with each data collection campaign, only grids showing evidence of a change were retained in the inspection program. Additional assurance regarding the adequacy of this inspection plan was obtained by a completely randomized inspection, involving 49 grids that showed that all inspection locations satisfied ASME code requirements. Evaluation of UT measurements taken through 2000 concluded that corrosion is no longer occurring at two (2) elevations, the 3rd elevation is undergoing a corrosion rate of 0.6 mils/year, while the 4th elevation is subject to 1.2 mils/year. The recent UT measurements (2004) confirmed that the corrosion rate continues to decline. The two elevations that previously exhibited no increase in corrosion continue the no corrosion increase trend. The rate of corrosion for the 3rd elevation decreased from 0.6 mils/year to 0.4 mils/year. The rate of corrosion for the 4th elevation decreased from 1.2 mils/year to 0.75 mils/year. After each UT examination campaign, an engineering analysis is performed to ensure the required minimum thickness is provided through the period of extended operation. Thus, corrosion of the drywell shell is considered a TLAA further described in Section 4.7.2.

The applicant concluded that the continued monitoring of the drywell for loss material through ASME Section XI, Subsection IWE, the Protective Coating Monitoring and Maintenance Program, and 10 CFR Part 50, Appendix J provide reasonable assurance that loss of material in inaccessible areas of the drywell will be detected prior to a loss of an intended function. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process. The ASME Section XI, Subsection IWE, the protective coating monitoring and maintenance, and 10 CFR Part 50 Appendix J programs are described in Appendix B.

The project team noted that the applicant did not address aging management of the portion of the drywell shell embedded in the drywell concrete floor. This area is inaccessible for inspection, but is potentially subject to wetting on both the inside and outside surfaces. The project team asked the applicant to submit its AMR for this inaccessible portion of the drywell shell.

In its response, the applicant stated that the embedded portion of the drywell shell is exempt from visual examination in accordance with IWE-1232. Pressure testing in accordance with 10 CFR Part 50, Appendix J, Type A test, is credited for managing aging effects of inaccessible portions of the drywell shell consistent with NUREG-1801.

The applicant pointed out that NUREG-1801 Vol. 2 Item Number II.B1.1-2, Aging Management Program (AMPs) column states that loss of material due to corrosion is not significant if the following conditions are satisfied:

- Concrete meeting the specifications of ACI 318 or 349 and the guidance of 201.2R was used for containment shell or liner,

- The concrete is monitored to ensure that it is free of cracks that provide path for water seepage to the surface of the containment shell or liner,
- The moisture barrier, at the junction where the shell or liner becomes embedded, is subject to aging management activities in accordance with ASME Section XI, Subsection IWE requirements, and
- Water ponding on the containment concrete floor are not common and when detected are cleaned up in a timely manner.

If any of the above conditions cannot be satisfied, then a plant-specific aging management program for corrosion is necessary."

The applicant indicated that its AMR results concluded that Oyster Creek satisfies the above requirements and a plant-specific aging management program is not required for corrosion of the embedded drywell shell. The Oyster Creek concrete meets the recommendations of ACI 318 and the guidance of ACI 201.2R-77. The drywell concrete floor will be monitored for cracks under the structures monitoring aging management program (B.1.31). Oyster Creek design does not include a moisture barrier. However the design provides a 9" high curb (min) around the entire drywell floor (except at the two trenches discussed below) to prevent any water accumulated on the floor from being in contact with the drywell shell. The curb is considered part of the drywell concrete floor and inspected for cracking under the structures monitoring program (B.1.31). The drywell floor is designed to slope away from the drywell shell towards the drywell sump for proper drainage. The sump level is monitored in the main control room in accordance with Technical Specifications, and actions are taken to ensure Technical Specifications limits are not violated. Should the sump fill and overflow leak rate cannot be monitored, a plant shutdown will be required to regain leak rate monitoring capability and determine the source of the leak.

The applicant further stated that during the investigative period to determine the extent of corrosion in the exterior surfaces of the sand bed region, two trenches were excavated in the drywell concrete floor. The purpose of the trenches was to expose the embedded drywell shell so that UT thickness measurements can be taken from inside the drywell in the sand bed region. Visual inspection and UT measurements did not identify corrosion as a concern on the exposed embedded drywell shell inside the drywell within the excavated trenches. The two trenches were sealed with an elastomer to prevent water intrusion into the embedded shell. Prior to entering the period of extended operation a one-time visual inspection of the embedded drywell shell, within the two trenches, will be performed by removing the sealant and exposing the embedded shell. Inspection and acceptance criteria will be in accordance with IWE. If visual inspection reveals corrosion that could impact drywell integrity, corrective actions will be initiated in accordance with the corrective action process to ensure that the drywell remains capable of performing its intended function. Following these inspections, the trenches will be resealed to continue protecting the embedded shell. In addition, one-time UT measurements will be taken and corrective actions will be initiated in accordance with the corrective action process to ensure that the drywell is capable of performing its intended function.

In its letter dated April 4, 2006, the applicant committed to the following: A visual examination of the drywell shell in the drywell floor inspection access trenches will be performed to assure that the drywell steel remains intact. If degradation is identified, the drywell shell condition will be evaluated and corrective actions taken, as necessary. These surfaces will either be inspected as part of the scope of the ASME Section XI, Subsection IWE inspection program, or they will be restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas. **This is Audit Commitment 3.5.2.2.1-1.**

In its letter dated May 1, 2006 (AmerGen Letter No. 2130-06-20328), the applicant committed to the following: In addition to AmerGen's previous commitment to perform one-time visual examinations of the drywell shell in the areas exposed by the trenches in the bottom of the drywell (reference AmerGen 4/4/06 letter to NRC), one-time Ultrasonic Testing (UT) measurements will be taken to confirm the adequacy of the shell thickness in these areas, providing further confidence that the drywell remains capable of performing its intended function. This commitment will be performed prior to entering the period of extended operation. **This is Audit Commitment 3.5.2.2.1-2.**

The applicant also noted that the inaccessible drywell shell in the sand bed region became accessible (from the outside surface) after removal of sand in 1992. The interface of the shell and the sand bed floor was cleaned, coated, and sealed with silicon sealant. The periodic coating inspection has not identified any coating degradation at the shell/concrete interface that would indicate that corrosion is occurring in the embedded portion of the shell.

On the basis of the information provided, the project team determined that the applicant will determine the condition of the inaccessible portion of the drywell shell embedded in the drywell concrete floor prior to entering the extended period of operation, based on the results of the inspection of the two trenches, and that corrective actions will be taken as necessary if degradation is found.

The project team evaluated the degradation history of the OCGS containment and the applicant's aging management commitments for the extended period of operation in its evaluation of the applicant's IWE aging management program (B.1.27). Three audit open items have been identified. See 3.0.3.2.22 of this audit report.

3.5.2.2.1.5 Loss of Prestress Due to Relaxation, Shrinkage, Creep, and Elevated Temperature

In Section 3.5.2.2.1.5 of the OCGS LRA, the applicant stated that loss of prestress of concrete containments is not applicable since Oyster Creek has a Mark I steel containment. The project team concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek has a Mark I steel containment.

3.5.2.2.1.6 Cumulative Fatigue Damage

In OCGS LRA Section 3.5.2.2.1.6, the applicant stated that fatigue is a TLAA, as defined in 10 CFR 54.3. Applicants must evaluate TLAAs in accordance with 10 CFR 54.21(c)(1). The NRR/DE staff evaluated this TLAA, and its evaluation is documented separately in Section 4 of the SER related to the OCGS LRA.

3.5.2.2.1.7 Cracking Due to Stress Corrosion Cracking

The project team reviewed OCGS LRA Section 3.5.2.2.1.7 against the criteria in SRP-LR Section 3.5.2.2.1.7.

SRP-LR Section 3.5.2.2.1.7 stated that cracking due to stress corrosion cracking of stainless steel penetration sleeves, penetration bellows, and dissimilar metal welds could occur in all types of PWR and BWR containments. Cracking due to SCC could also occur in stainless steel vent line bellows for BWR containments. The existing program relies on ASME Section XI, Subsection IWE and10 CFR Part 50, Appendix J to manage this aging effect. The GALL Report recommends further evaluation of additional appropriate examinations/evaluations implemented to detect these aging effects for stainless steel penetration sleeves, penetration bellows and dissimilar metal welds, and stainless steel vent line bellows.

In the OCGS LRA Section 3.5.2.2.1.7, the applicant addressed cracking of stainless steel penetration sleeves, penetration bellows, and dissimilar metal welds due to stress corrosion cracking. The OCGS LRA stated that at Oyster Creek, cracking of containment penetrations (including penetration sleeves, penetration bellows, and dissimilar metal welds) due to cyclic loading is considered metal fatigue and is addressed as a TLAA in Section 4.6.

Stress corrosion cracking is an aging mechanism that requires the simultaneous action of a corrosive environment, sustained tensile stress, and a susceptible material. Elimination of any one of these elements will eliminate susceptibility to SCC. Stainless steel elements of primary containment and the containment vacuum breakers system, including dissimilar welds, are susceptible to SCC. However these elements are located inside the containment drywell or outside the drywell, in the reactor building, and are not subject to corrosive environment as discussed below.

The drywell is made inert with nitrogen to render the primary containment atmosphere non-flammable by maintaining the oxygen content below 4% by volume during normal operation. The normal operating average temperature inside the drywell is less than 139˚F and the relative humidity range is 20-40%. The reactor building normal operating temperature range is 65˚F – 92˚F; except in the trunion room where the temperature can reach 140˚F. The relative humidity is 100% maximum. Both the containment atmosphere and indoor air environments are non-corrosive (chlorides <150 ppb, sulfates <100 ppb, and fluorides <150 ppb).

Thus, SCC is not expected to occur in the containment penetration bellows, penetration sleeves, and containment vacuum breakers expansion joints, piping and piping components, and dissimilar metal welds. A review of plant operating experience did not identify cracking of the components and primary containment leakage has not been identified as a concern. Therefore, the existing 10 CFR Part 50 Appendix J leak testing and ASME Section XI, Subsection IWE, are adequate to detect cracking. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process. The ASME Section XI, Subsection IWE and 10 CFR Part 50 Appendix J programs are described in Appendix B.

The project team asked the applicant to address whether the problems encountered at Dresden/Quad Cities with cracking of expansion bellows is applicable to OCGS. The applicant stated that the problems were unique to Dresden/Quad Cities and do not apply to OCGS. On the basis that the environment conducive to SCC does not exist at OCGS, the project team found the applicant’s further evaluation for cracking due to SCC to be acceptable.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.5.2.2.1.7 for further evaluation.

3.5.2.2.1.8 <u>Cracking Due to Cyclic Loading</u>

In Section 3.5.2.2.1.7 of the OCGS LRA, the applicant stated that cracking of containment penetrations (including penetration sleeves, penetration bellows, and dissimilar metal welds) due to cyclic loading is considered metal fatigue, and is addressed as a TLAA in LRA Section 4.6.

The project team concurred with the applicant's further evaluation, that this aging effect is addressed as a TLAA in LRA Section 4.6.

3.5.2.2.1.9 Loss of Material (Scaling, Cracking, and Spalling) Due to Freeze-Thaw

In Section 3.5.2.2.1.8 of the OCGS LRA, the applicant stated that loss of material due to freeze-thaw of concrete containments is not applicable since Oyster Creek has a Mark I steel containment. The project team concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek has a Mark I steel containment.

3.5.2.2.1.10 Cracking Due to Expansion and Reaction with Aggregate, and Increase in Porosity and Permeability Due to Leaching of Calcium Hydroxide

In Section 3.5.2.2.1.8 of the OCGS LRA, the applicant stated that cracking due to expansion and reaction with aggregates of concrete containments is not applicable since Oyster Creek has a Mark I steel containment. The project team concurred with the applicant's evaluation that this aging effect is not applicable since Oyster Creek has a Mark I steel containment.

3.5.2.2.2 Safety-Related and Other Structures and Component Supports

3.5.2.2.2.1 Aging of Structures Not Covered by Structures Monitoring Program

In the OCGS LRA, Section 3.5.2.2.2.1, the applicant addressed further evaluations in accordance with the January 2005 Draft Revision of the SRP-LR. The applicant provided its reconciliation to the further evaluations listed in the September 2005 Revision 1 of the SRP-LR in Attachment 3, Items T-04, T-06, and T-11 of its reconciliation document. The project team reviewed the reconciliation document against the criteria in Section 3.5.2.2.2.1 of SRP-LR, Rev. 1, for items (1), (2), and (3). Based on its review of LRA Section 3.5.2.2.2.1, the project team determined that the applicant's reconciliation also applies to items (4), (5), and (6) in SRP-LR Section 3.5.2.2.2.1; i.e., the structures monitoring program is credited. Item (7) is not applicable to Oyster Creek.

SRP-LR Section 3.5.2.2.2.1 states that the GALL Report recommends further evaluation of certain structure/aging effect combinations if they are not covered by the structures monitoring program. This includes (1) cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel for Groups 1-5, 7, 9 structures (T-04); (2) increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack for Groups 1-5, 7, 9 structures (T-06); (3) loss of material due to corrosion for Groups 1-5, 7, 8 structures (T-11); (4) loss of material (spalling, scaling) and cracking due to freeze-thaw for Groups 1-3, 5, 7-9 structures; (5) cracking due to expansion and reaction with aggregates for Groups 1-5, 7-9 structures; (6) cracks and distortion due to increased stress levels from settlement for Groups 1-3, 5-9 structures; and (7) reduction in foundation strength, cracking, differential settlement due to erosion of porous concrete subfoundation for Groups 1-3, 5-9 structures. The GALL Report recommends further evaluation only for structure/aging effect combinations that are not within the structures monitoring program.

The SRP-LR further stated that lock up due to wear could occur for Lubrite® radial beam seats in BWR drywell, RPV support shoes for PWR with nozzle supports, steam generator supports, and other sliding support bearings and sliding support surfaces. The existing program relies on the structures monitoring program or ASME Section XI, Subsection IWF to manage this aging effect. The GALL Report recommends further evaluation only for structure/aging effect combinations that are not within the ISI (IWF) or structures monitoring program. (NOTE: See 3.5.2.1 of this audit report for the project team's assessment of the applicant's aging management results for lock up due to wear of Lubrite® radial beam seats in BWR drywell.)

In Attachment 3, Item T-04 of its reconciliation document, the applicant stated that there is no change required to the Oyster Creek LRA due to this item change. The wording for further evaluation was changed from not required if within the scope of the applicant's structures monitoring program, to required if not within the scope of the applicant's structures monitoring program. This item is within the scope of Oyster Creek's structures monitoring program, therefore further evaluation is not required.

In Attachment 3, Item T-06 of its reconciliation document, the applicant stated that there is no change required to the Oyster Creek LRA due to this item change. The environment for this item, concrete: interior and above grade exterior, changed from ?aggressive environment" to ?air – indoor uncontrolled or air – outdoor". The wording for further evaluation was changed from not required if within the scope of the applicant's structures monitoring program, to required if not within the scope of the applicant's structures monitoring program. Each instance of use of this item is within the scope of Oyster Creek's structures monitoring program, therefore further evaluation is not required.

In Attachment 3, Item T-11 of its reconciliation document, the applicant stated that there is no change required to the Oyster Creek LRA due to this item change. The wording for further evaluation was changed from not required if within the scope of the applicant's structures monitoring program, to required if not within the scope of the applicant's structures monitoring program. This item is within the scope of Oyster Creek's structures monitoring program, therefore further evaluation is not required.

The project team concurred with the applicant's determination that no further evaluation is required, on the basis that the structures monitoring program is credited for aging management.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.1 for further evaluation.

3.5.2.2.2.2 Aging Management of Inaccessible Areas

3.5.2.2.2.2.1 Aging Management of Inaccessible Areas [Item 1]

In the OCGS LRA, Section 3.5.2.2.2.2, the applicant addressed further evaluations in accordance with the January 2005 Draft Revision of the SRP-LR. The applicant provided its reconciliation to the further evaluations listed in the September 2005 Revision 1 of the SRP-LR in Attachment 3, Item T-01 of its reconciliation document. The project team reviewed the reconciliation document against the criteria in Section 3.5.2.2.2.2.1 of SRP-LR, Rev. 1.

SRP-LR Section 3.5.2.2.2.2.1 stated that loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade inaccessible concrete areas of Groups 1-3, 5 and 7-9 structures (T-01). The GALL Report recommends further evaluation of this aging effect for inaccessible areas of these Groups of structures for plants located in moderate to severe weathering conditions.

In Attachment 3, Item T-01 of its reconciliation document, the applicant stated that there is no change required to the Oyster Creek LRA due to this item change. For inaccessible areas, as described in the UFSAR Section 3.8.4.6, ?Materials, Quality Control and Special Construction Techniques", concrete is designed consistent with ACI 318 recommendations to provide workable concrete of homogeneous structure which, when hardened, will have durability, impermeability and the specified strength. Testing of concrete was performed in accordance with ASTM Standards specified in ACI 318 to ensure the desired quality of concrete is furnished. The strength quality of the concrete was established by tests made in advance of the beginning of operations using a maximum slump of four inches. Specimens were tested and cured in accordance with ASTM C39.

The review of design and construction documents indicated that the specified air content is 4 to 6 percent. Water-to-cement ratio was based on the strength required by the design considering the maximum slump of four inches. Curves representing the relation between the water content and the average 28-day compressive strength were established for a range of values including the compressive strengths specified. The curves were established by at least three points, each point represented average values from at least four test specimens. The maximum allowable water content for each class of concrete was determined from the curves and corresponded to a compressive strength of 15 percent greater than that specified for that class of concrete. A review of documentation for a sample of class 4LA (4000 psi) concrete cylinder tests shows that the 28-day strength meets or exceeds the specified 4000 psi compressive strength.

Inspections conducted in accordance with the structures monitoring program have identified minor loss of material (spalling, scaling) and cracking which could be attributed to freeze-thaw in accessible areas. Engineering evaluation of the identified loss of material and cracking concluded it is not significant to impact the intended function of the affected structure.

Based on the above evaluation, the applicant concluded that loss of material and cracking due to freeze-thaw is not significant for inaccessible areas. Thus, a plant-specific aging management program is not required.

The project team asked the applicant for more information about aging management of inaccessible concrete areas, specifically to confirm that the OCGS structures monitoring program credited for license renewal will inspect all inaccessible areas that may be exposed by excavation for any reason, whether the environment is considered aggressive or not, and also will inspect any inaccessible area where observed conditions in accessible areas, which are exposed to the same environment, show that significant concrete degradation is occurring.

In its response, the applicant stated that Oyster Creek will inspect inaccessible areas of structures in the scope of license renewal that are exposed by excavation for any reason, whether the environment is considered aggressive or not. Inaccessible areas of structures in the scope of license renewal will be inspected if observed conditions in accessible areas, which are exposed to the same environment, show that significant concrete degradation is occurring.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.2.1 for further evaluation The project team found that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.2.2.2.2 Aging Management of Inaccessible Areas [Item 2]

In the OCGS LRA, Section the applicant addressed further evaluations in accordance with the January 2005 Draft Revision of the SRP-LR. The applicant provided its reconciliation to the further evaluations listed in the September 2005 Revision 1 of the SRP-LR in Attachment 3, Item T-03 of its reconciliation document. The project team reviewed the reconciliation document against the criteria in Section 3.5.2.2.2.2.2 of SRP-LR, Rev. 1.

SRP-LR Section 3.5.2.2.2.2.2 stated that cracking due to expansion and reaction with aggregates could occur in below-grade inaccessible concrete areas for Groups 1-5 and 7-9 structures (T-03). The GALL Report recommends further evaluation of inaccessible areas of these Groups of structures if concrete was not constructed in accordance with the recommendations in ACI 201.2R-77.

In Attachment 3, Item T-03 of its reconciliation document, the applicant stated that there is no change required to the Oyster Creek LRA due to this item change. The wording for further evaluation was changed from not required if within the scope of the applicant's structures monitoring program, and stated conditions are satisfied for inaccessible areas, to required if not within the scope of the applicant's structures monitoring program, or concrete was not constructed as stated for inaccessible areas. This item is within the scope of Oyster Creek's structures monitoring program, therefore further evaluation is not required. The staff agrees with the applicant's assessment.

The project team determined that the recommendations of SRP-LR Section 3.5.2.2.2.2.2 can be achieved by the applicant's commitments to (1) opportunistic inspection of normally inaccessible areas if they are exposed for any reason, and (2) inspection of inaccessible areas of structures if observed conditions in accessible areas, which are exposed to the same environment, show that significant concrete degradation is occurring. See 3.5.2.2.2.2.1 of this audit report.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.2.2 for further evaluation.

3.5.2.2.2.2.3 Aging Management of Inaccessible Areas [Item 3]

In the OCGS LRA, the applicant addressed further evaluations in accordance with the January 2005 Draft Revision of the SRP-LR. The applicant provided its reconciliation to the further evaluations listed in the September 2005 Revision 1 of the SRP-LR in Attachment 3, Item T-08 of its reconciliation document. The project team reviewed the reconciliation document against the criteria in Section 3.5.2.2.2.2.3 of SRP-LR, Rev. 1.

SRP-LR Section 3.5.2.2.2.2.3 stated that cracks and distortion due to increased stress levels from settlement and reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations could occur in below-grade inaccessible concrete areas of Groups 1-3, 5 and 7-9 structures (T-08). The existing program relies on structures monitoring program to manage these aging effects. Some plants may rely on a de-watering system to lower the site ground water level. If the plant's CLB credits a de-watering system, the GALL Report recommends verification of the continued functionality of the de-watering system during the period of extended operation. The GALL Report recommends no further evaluation if this activity is included in the scope of the applicant's structures monitoring program.

In Attachment 3, Item T-08 of its reconciliation document, the applicant stated that there is no change required to the Oyster Creek LRA due to this item change. Oyster Creek does not rely on a de-watering system for control of settlement. The wording for further evaluation was changed from not required if within the scope of the applicant's structures monitoring program, to required if not within the scope of the applicant's structures monitoring program. This item is within the scope of Oyster Creek's structures monitoring program, therefore further evaluation is not required. The staff agrees with the applicant's assessment.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.2.3 for further evaluation.

3.5.2.2.2.2.4 <u>Aging Management of Inaccessible Areas [Item 4]</u>

In the OCGS LRA, the applicant addressed further evaluations in accordance with the January 2005 Draft Revision of the SRP-LR. The applicant addressed aging management of inaccessible areas in OCGS LRA Section 3.5.2.2.2.2. The project team reviewed OCGS LRA Section 3.5.2.2.2.2 against the criteria in Section 3.5.2.2.2.2.4 of the September 2005 Revision 1 of the SRP-LR.

SRP-LR Section 3.5.2.2.2.2.4 stated that increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack; and cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel could occur in below-grade inaccessible concrete areas of Groups 1-3, 5 and 7-9 structures. The GALL Report recommends further evaluation of plant-specific programs to manage these aging effects in inaccessible areas of these Groups of structures if the environment is aggressive.

In Section 3.2.2.2.2 of the OCGS LRA, the applicant addressed cracking, spalling, and increases in porosity and permeability due to aggressive chemical attack; and cracking, spalling, loss of bond, and loss of material due to corrosion of embedded steel in below-grade inaccessible concrete areas. The applicant stated that recent Oyster Creek groundwater analysis results (pH: 5.6 – 6.4, chlorides: 3 – 138 ppm, and sulfates: 7 – 73 ppm) have shown that the groundwater at Oyster Creek is not aggressive for Groups 2-3, 8-9 structures. Therefore, further evaluation of below-grade inaccessible concrete areas for Groups 2, and 8-9 structures is not required. Similarly inaccessible areas of Group 3 structures are not exposed to aggressive environment except for fire water pumphouses (fresh water pumphouse only). Further evaluation of group 3 structures, other than fresh water pumphouse is not required.

The fresh water pumphouse reinforced concrete is subject to slightly aggressive water from the Fire Pond Dam (pH: 4.8, chlorides = 12 ppm, and sulfates = 6 ppm). Inaccessible areas will be inspected if excavated for any reason, or if observed conditions in accessible areas, which are exposed to the same environment, show that significant concrete degradation is occurring.

The structures monitoring program will be enhanced to include periodic groundwater monitoring in order to demonstrate that the below grade environment remains non-aggressive. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process. The structures monitoring program is described in Appendix B.

The project team asked the applicant for more information about the water-flowing and aggressive environments for the freshwater pump house and the service water seal well, and the operating experience for these structures, including whether degradation has been observed, monitored, and/or repaired, and whether there are any special considerations (e.g., more frequent inspections, more detailed inspections) over and above the normal structures monitoring program inspection procedures.

In response, the applicant stated that the freshwater pump house is located at the fire pond dam south west of the reactor building outside the protected area. The pump house supplies water for the fire protection system. As discussed in the LRA, paragraph 3.5.2.2.2.2, the pump house is subject to ?Raw Water – Fresh Water" environment described in LRA Table 3.0-2. Chemistry analysis of the water indicates that it is slightly aggressive because pH=4.8 and is less than 5.5 specified in NUREG-1801. The chloride and sulfate contents are below the aggressive limits (12 ppm and 6 ppm respectively) specified in NUREG-1801. The water is generally standing; except for low natural stream velocity, and low velocity due to fire pump operation, thus the label "water-flowing". The freshwater pump house is monitored on a frequency of 4 years under the Structures Monitoring Program B.1.31). Inspection of accessible areas of the structure above the water level was conducted in 2002. The inspection results indicate that the structure is structurally sound. Operating experience (OE) review did not identify objective evidence that inaccessible and under water areas of the structure have been inspected previously. The OE review noted that the pump bays were desilted in late 2003. There were no reports of structural concerns by the desilting team. The OE review also did not indicate that repairs were made in the past. The freshwater pump house is not subject to special considerations, such as more frequent or detailed inspections above the normal structure monitoring program. There are no special considerations for inspecting inaccessible and underwater portion of the structure under the current term. However the structure will be subject to special considerations during the period of extended operation as discussed below.

The service water system (SWS) Seal Well is a reinforced concrete 2-cell junction box, partly above ground, that is in the flow path of the service water system return line to the discharge canal. The 2 cells are separated by a 4-foot high concrete wall that acts as a weir over which water discharged from SWS line overflows and drains out through a 30" diameter drain at the bottom of the second cell. The drain line is connected to the roof drains and overboard discharge system (Section 2.3.3.33) which conveys water to the discharge canal. The weir overflow was considered a "water-flowing" environment. The internal surfaces of the junction box are subject to "raw water-salt water" environment, as described in LRA Table 3.0-2. The environment is aggressive (pH = 7.9, chlorides = 14,659 ppm, and sulfates = 1,419 ppm) because the chloride limit specified in NUREG-1801 (< 500 ppm) is exceeded.

The SWS Seal Well is not currently monitored under the structures monitoring program (B.1.31). There is documented evidence that the SWS Seal Well has been inspected previously in October 1999. As a result of this inspection, there are records indicating interior surfaces of the structure were coated with an elastomer to protect against concrete degradation. The coating, however, is not monitored on a regular basis such that it could be credited for managing aging of concrete. Observed exterior surfaces of the above ground structure that are exposed to the water-flowing and aggressive raw water-salt water environment described above on internal surfaces, shows rust stains and cracking. However the structure appears acceptable. An Issue Report (IR), was issued in accordance with the corrective action process to determine why the structure is not in the scope of the maintenance rule structures monitoring program, and to evaluate its condition for the current term. In the LRA, AmerGen has committed to including the SWS seal well in the scope of the structures monitoring program. The structure will be subject to special consideration if the initial inspection, discussed below, shows that it is required.

The applicant stated that, as indicated in LRA Tables 3.5.2.1.9 and 3.5.2.1.12, the freshwater pump house and the SWS seal well will be monitored under the structures monitoring program on a frequency of 4 years during period of extended operation. The initial inspection will be completed prior to entering the period of extended operation. The results of this inspection will be evaluated to determine if any corrective actions are required or if more frequent inspections are warranted to ensure that the intended function of the structures is maintained. Inaccessible areas of the structures will be inspected as per the structures monitoring program if exposed by excavation for any reason, and if observed conditions in accessible areas, which are exposed to the same environment, show that significant concrete degradation is occurring.

The project team determined that the applicant's approach to aging management for the freshwater pump house and the service water seal well is appropriate. The need to inspect more frequently than every 4 years will be determined prior to entering the period of extended operation.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.2.4 for further evaluation.

3.5.2.2.2.2.5 Aging Management of Inaccessible Areas [Item 5]

In the OCGS LRA, the applicant addressed further evaluations in accordance with the January 2005 Draft Revision of the SRP-LR. The applicant provided its reconciliation to the further evaluations listed in the September 2005 Revision 1 of the SRP-LR in Attachment 3, Item T-02 of its reconciliation document. The project team reviewed the reconciliation document against the criteria in Section 3.5.2.2.2.2.5 of SRP-LR, Rev. 1.

SRP-LR Section 3.5.2.2.2.2.5 stated that increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide could occur in below-grade inaccessible concrete areas of Groups 1-3, 5 and 7-9 structures. The GALL Report recommends further evaluation of this aging effect for inaccessible areas of these groups of structures if concrete was not constructed in accordance with the recommendations in ACI 201.2R-77.

In Attachment 3, Item T-02 of its reconciliation document, the applicant stated that there is no change required to the Oyster Creek LRA due to this item change. Further evaluation is only required for inaccessible areas if concrete was not constructed as stated (in accordance with the recommendations in ACI 201.2R-77). In the Oyster Creek LRA, the use of this line item is not for inaccessible areas. Accessible areas inspections are performed in accordance with the structures monitoring program, per September 2005 GALL.

The project team determined that the applicant has eliminated increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide as an applicable aging effect/mechanism for inaccessible concrete areas at Oyster Creek, based on the quality of below-grade concrete.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.2.5 for further evaluation.

3.5.2.2.2.3 Reduction of Strength and Modulus of Concrete Structures Due to Elevated Temperature

In the OCGS LRA, the applicant addressed further evaluations in accordance with the January 2005 Draft Revision of the SRP-LR. The applicant addressed aging management for elevated temperature in concrete in OCGS LRA Section 3.5.2.2.2.1(8). The project team reviewed OCGS LRA Section 3.5.2.2.2.1(8) against the criteria in Section 3.5.2.2.2.2.3 of the September 2005 Revision 1 of the SRP-LR.

SRP-LR Section 3.5.2.2.2.3 stated that reduction of strength and modulus of concrete due to elevated temperatures could occur in PWR and BWR Group 1-5 concrete structures. For any concrete elements that exceed specified temperature limits, further evaluations are recommended. Appendix A of ACI 349-85 specifies the concrete temperature limits for normal operation or any other long-term period. The temperatures shall not exceed 150˚F except for local areas, which are allowed to have increased temperatures not to exceed 200˚F. The GALL Report recommends further evaluation of a plant-specific program if any portion of the safety-related and other concrete structures exceeds specified temperature limits, i.e., general area temperature greater than 66˚C (150˚F) and local area temperature greater than 93˚C (200˚F). The acceptance criteria are described in Branch Technical Position RLSB-1 (Appendix A.1 of this SRP-LR).

In the OCGS LRA Section 3.5.2.2.2.1(8), the applicant addressed reduction of strength and modulus of concrete due to elevated temperatures. The applicant stated that for loss of strength and modulus of concrete structures due to elevated temperatures for Groups 2-5, GALL recommends a Plant Specific AMP and further evaluation if the general temperature is greater than 150ºF or if the local temperature is greater than 200˚F. For Oyster Creek, the structures monitoring program is used to manage cracking of concrete structures exposed to elevated temperatures.

The applicant indicated that concrete temperature limits specified in the GALL Report are exceeded only in a section of the reactor building (Group 2) drywell shield wall that encloses the containment drywell head. Thermocouples mounted on the head, in the general area of the shield wall, indicated a maximum temperature of 285˚F. Engineering analysis predicted that the average temperature through the 5' thick concrete wall could be in the range of 180˚F-215˚F; considering a worst case thermal environment inside the containment of 340˚F. As a result, an investigation was initiated to evaluate the impact of the elevated temperature on the structural integrity of the shield wall. The initial inspection of the shield wall identified concrete cracking in the area that is subject to high temperature. A map of the cracked area that includes crack length and width was developed for future monitoring.

Subsequently, an engineering evaluation was conducted to assess the impact of the elevated temperature on the drywell shield wall. For this purpose, a finite element model was created considering the geometry of the shield wall and structural elements connected to it. The analysis was based on a temperature of 285˚F and a reduced concrete compressive strength that accounts for temperature-induced reduction. The results concluded that concrete and rebar stress limits are in accordance with ACI 349 criteria with an adequate safety margin. NRC staff review found the analysis acceptable and concluded that the wall is capable of performing its intended function. The staff also recommended condition monitoring of the drywell shield wall to ensure its continued function. The wall has been included in the scope of the structures monitoring program and inspected periodically to ensure its continued function. Observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process. The structures monitoring program is described in Appendix B.

In order to facilitate its evaluation, the project team asked the applicant to provide the following additional information related to the elevated temperature condition in the reactor building drywell shield wall:

- When was the condition first discovered,
- What was the extent of the elevated temperature region,
- What was the extent of the cracked region (distribution, length, width of cracks) when first discovered,
- When did NRC conclude that this condition is acceptable, and did this conclusion consider the remaining operating life of OC at that time,
- Describe the monitoring program, including the dates and quantitative results obtained, since NRC acceptance of the condition,
- Currently, what is the extent of the elevated temperature region and what is the extent of the cracked region (distribution, length, width of cracks),
- Has there been a need to conduct re-analysis or make any repairs,
- Is the license renewal commitment under the OCGS SMP greater than, equal to, or less than the condition monitoring activities currently being conducted to satisfy the NRC staff's recommendation

In response, the applicant stated that the drywell shield wall elevated temperature concern surfaced in early to mid-1980's. The issue was evaluated as part of NUREG-0822, ?Integrated Plant Safety Assessment, Systematic Evaluation Program, Oyster Creek Nuclear Generating Station," January 1983, Topic III-7.B.

The applicant further stated that a review of the current licensing basis information did not identify documents that provide details on the extent of the cracked region when it was first discovered in mid-1980's. The applicant was able to conclude that the condition of the wall was monitored after it was discovered. However, specific criteria such as distribution, width, and length of cracks were not identified. The earliest document that provides this information is an inspection report prepared in 1994. This report has been used since 1994 as a benchmark against which subsequent observed shield wall condition is evaluated. Observed cracks on the outside of drywell shield wall, as documented in the 1994 inspection report, show that the entire shield wall above elevation 95'-3" may be affected by the elevated temperature. Distribution of the cracks is generally random. Crack widths are generally hairline; with no cracks wider than 1/32".

The applicant also stated that the NRC staff evaluation of information submitted by GPU, the previous owner of Oyster Creek, on the drywell shield wall elevated temperature began in 1986. In its Safety Evaluation dated October 24, 1986 (Letter, J. Zwolinsky, NRC, to P. Fiedler, GPUN, with a Safety Evaluation 4.12, SEP Topic III-7.B, NRC Information Request Form of NUREG-0822, Design Codes, Design Criteria and Load Combinations, dated October 29, 1986), the staff required further investigation to complete its evaluation. GPU transmitted the requested information, in several correspondences between 1990 through 1993. The staff completed its review of the submitted information and concluded in a Safety Evaluation dated May 11, 1994 that the drywell shield wall is capable of performing its intended function (Letter from Alexander W. Dromerick, Jr., NRC, to J. Barton, GPU, "Oyster Creek Nuclear Generating station – Evaluation of Effects of High Temperature on drywell Shield Wall and Biological Shield Wall, SEP Topic III-7.B "Design Codes, Design Criteria, Load Combinations, and Reactor Cavity

Criteria" (TAC No. M76879) dated May 11, 1994). The May 11, 1994 Safety Evaluation did not specify that the conclusion is based on the remaining operating life of Oyster Creek.

As recommended by the NRC staff in their May 11, 1994 Safety Evaluation, Oyster Creek implemented a periodic crack monitoring program. The program consists of visual inspection of drywell shield wall above elevation 95’-3" every refueling outage (Letter from R.W. Keaten to U.S. NRC, "Oyster Creek Nuclear Generating Station (OCNGS) Docket 50-219 SEP Topic III-7B, drywell Shield Wall Integrity", dated April 19, 1994). The benchmark inspection was conducted in April 1994 to record the surface condition of the drywell shield wall, including the crack patterns, crack length, and width. In October 1996, during the refueling outage, the applicant performed a second inspection was performed to assess the condition of the drywell shield wall while the reactor cavity is flooded with water. The following conditions were observed by the applicant:

1. The crack pattern remained unchanged
2. Some observable hair line cracks may be newly developed or may be un-recorded from the last inspection
3. No cracks wider than 1/32" were observed
4. No spalling or new scaling/peeling was observed
5. There is evidence of growing water stains from the pipe penetration and cracks.

The applicant further stated that engineering evaluation concluded that this condition is local and has no impact on structural integrity of the wall. The applicant concluded from the 1998 inspection that:

1. The crack pattern remained unchanged from previous inspection.
2. The bottom 8' of the wall was repainted since the last inspection and new fine cracks were observed. However, no new significant cracks were observed.
3. Inspection of the wall after plant shutdown showed that the surface cracking were mostly closed and no excessive cracking
4. No concrete spalling was observed
5. New water stains were observed. However no significant leaching or staining was observed.

The applicant’s structural engineer who performed the inspection concluded that the drywell shield walls were structurally adequate to perform their intended functions.

The applicant’s 2002 inspection report noted that the structural condition of the shield walls was the same as that observed in 1998. Cracks observed were minor and that the walls were adequate to perform their intended functions.

The applicant’s 2005 inspection report noted that the shield walls were in good/sound condition and capable of performing their intended function. The minor hairline cracks and rust stains were the same as noted in previous inspections.

The applicant further stated that, as evidenced by operating experience discussed above, the extent of the elevated temperature region and the extent of the cracked region have not significantly changed since the benchmark report of 1994. Additional minor cracks and stains have been observed since that time. However they were not considered significant enough to impact the intended function of the drywell shield wall. A re-analysis was performed for GPU by ABB Impell Corporation (Report #0037-00196-0) and transmitted to NRC in November 19, 1993

(Letter, R. Keaton, GPUN, to NRC, ?Response to Request for Additional Information on Drywell Temperature (SEP Topic III-7.B)," dated November 19, 1993). There has been no need for repairs. The license renewal commitment under the Oyster Creek structures monitoring aging management is equal to the condition monitoring activities conducted under the current term to satisfy NRC staff recommendations.

As a follow-up to the applicant's response, the project team reviewed the May 11, 1994 letter from A. Dromerick and the November 19, 1993 letter from R. Keaton referenced above, along with ABB Impell Corporation Report # 03-0370-1341, ?Oyster Creek Nuclear Generating Station Structural Evaluation of the Spent Fuel Pool," Rev. 0, June 29, 1992. Based on its review, the project team had a concern that several potential aging issues may not have not been adequately addressed, in consideration of an additional 20 years of operation. These relate to known degradation of the drywell shield wall (DSW), the biological shield wall (BSW), and the spent fuel pool supporting structural elements. The project team asked the applicant to review the letter from A. Dromerick, Jr. (NRC) to J. Barton (GPU), "Oyster Creek Nuclear Generating station – Evaluation of Effects of High Temperature on drywell Shield Wall and Biological Shield Wall, SEP Topic III-7.B "Design Codes, Design Criteria, Load Combinations, and Reactor Cavity Criteria" (TAC No. M76879) dated May 11, 1994, and describe how the applicant has implemented the following elements of the staff's SER:

> (1) The staff's crack width acceptance criterion (0.02 inch), above which repairs should be made to prevent water intrusion and potential corrosion of rebar in the drywell shield wall.
>
> (2) The OCGS statement in the cited April 19, 1994 letter from R.W. Keaten to U.S. NRC that it is developing procedures for monitoring the condition of the DSW during each refueling outage.
>
> (3) The OCGS statement cited April 19, 1994 letter from R.W. Keaten to U.S. NRC that it has assigned a structural-system engineer to the OCGS site who is responsible for ensuring that the structures at the site are monitored and evaluated. (NRC letter to GPU states: The staff believes that this blanket commitment by the licensee, if properly implemented, would ensure the continued function of the BSW.)

The applicant was also asked to address the following questions:

> (4) Regarding the conclusion in the cited IMPELL Report, Section 5.4 Conclusion (4), related to the effects of consolidated fuel loads, has OCGS implemented a fuel rack change that increases the total fuel load in the spent fuel pool?
>
> (5) Regarding the cracking in the spent fuel area that the cited analysis predicted and compared to actual observations of cracking, what is the applicant's aging management commitment for these cracks?.

In response to the project team's follow-up question, the applicant stated the following:

> (1) Cracking of the drywell shield wall is monitored under the structures monitoring program. The program requires visual inspection of the shield wall for new cracks, crack growth and staining of the concrete as described in reference 4. An engineer with a B.S. degree, or a professional engineer, who has a minimum of five years experience working on nuclear structures, conducts inspections. Acceptance criteria are in accordance with

ACI 349, which states that passive cracks less than 0.015 inches are acceptable without further evaluation. This criteria envelopes the staff recommended 0.02 inches crack width criteria for the drywell shield wall. The current procedure does not specify a numerical value for crack width, rather the procedure relies on qualitative assessment by the qualified engineer to establish if observed cracks meet the guidance in ACI 349 and whether they could impact structural integrity of the wall. Previous inspection results, described previously indicate that the cracks are generally hairline that require no repair, and that the cracks have exhibited no significant change over the years. The structures monitoring program (B.1.31) implementing procedure will be enhanced to add the staff recommended criteria for the drywell shield wall crack width (0.02-inch).

(2) The statement in the cited April 19, 1994 letter from R.W. Keaten to U.S. NRC, ?GPU Nuclear is developing a program to ensure monitoring of concrete conditions during refueling outage and a formal guideline for performing the monitoring (e.g. visual inspections for crack growth and/or staining of the concrete)." is related to actions planned by GPU to implement a formal monitoring program. This planned formal program has been incorporated into the structures monitoring program as discussed in item (1) above. The normal inspection frequency of the structures monitoring program of 4 years was reduced to every refueling outage for the drywell shield wall consistent with the statement in cited letter.

(3) Oyster Creek has assigned a structural system engineer to monitor the condition of the drywell shield wall as well as other structures. The engineer is a licensed professional engineer with a minimum of 5 years experience with nuclear structures. Inspection and acceptance criteria are as discussed above. Inspection frequency is every refueling outage as stated in the cited April 19, 1994 letter from R.W. Keaten to U.S. NRC. The enhanced procedure will incorporate the NRC staff recommended 0.02 inch crack width acceptance criterion to be used for future inspections.

(4) The conclusion cited in ABB IMPELL Report #03-0370-1341, Section 5.4, conclusion 4, related to the effects of consolidated fuel loads is not implemented at Oyster Creek. The term consolidated fuel refers to removing the hardware from fuel bundles, such as channels and end plates, to allow for storage of greater quantity of spent fuel in the high density racks. The consolidated fuel loads are therefore greater than loads that are a result of the fuel rack change. The ABB IMPELL analysis included the consolidated fuel load in one of the load combinations to determine if the spent fuel pool structure will support it. However, as stated above, Oyster Creek does not store fuel in the spent fuel storage pool in a consolidated form.

(5) With respect to the cracking in the spent fuel pool area cited in ABB IMPELL analysis, Oyster Creek has observed cracks on the concrete girder along Column Line RE, and the bottom of the floor slab beneath the spent fuel pool north wall and, the drywell shield wall cracking. The observed cracks were attributed to temperature conditions and little cracking, if any, takes place under sustained loads. As cited in the ABB IMPELL Report, cracking predicted by the analysis is closely correlated with observed cracking. The analysis showed that the spent fuel pool structure is in full compliance with ACI 349-80 for all loads for which the plant was licensed. The analysis also concluded that the spent fuel pool structure is capable of supporting the consolidated fuel load; but the stress margin in certain components is zero. The zero margin in this case is academic since Oyster Creek does not store fuel in a consolidated form. Subsequently, four additional fuel racks were installed in the year 2000. A finite element analysis of the fuel pool

structure was performed by Holtec International and is documented in Holtec Report HI-981983, "Licensing Report for Storage Capacity Expansion of Oyster Creek Spent Fuel Pool", Revision 4, dated June 15, 1999. Monitoring of the cracks identified in the spent fuel pool area is included in the existing Oyster Creek structures monitoring program (B.1.31). The program is credited for aging management of the cracks during the period of extended operation.

The project team reviewed the applicant's responses, and concluded that the applicant's program to manage concrete cracking in the drywell shield wall (DSW), the biological shield wall (BSW), and the spent fuel pool supporting structural elements is adequate, based on the 2-year inspection frequency, the inclusion of a quantitative acceptance criterion for crack width, consistent with NRC staff recommendations, and the apparent stability of the existing crack patterns and crack widths.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.3 for further evaluation.

3.5.2.2.2.4 Aging Management of Inaccessible Areas for Group 6 Structures

3.5.2.2.2.4.1 Aging Management of Inaccessible Areas for Group 6 Structures [Item 1]

In the OCGS LRA, the applicant addressed further evaluations in accordance with the January 2005 Draft Revision of the SRP-LR. The applicant provided its reconciliation to the further evaluations listed in the September 2005 Revision 1 of the SRP-LR in Attachment 3, Items T-18 and T-19 of its reconciliation document. The project team reviewed the reconciliation document against the criteria in Section 3.5.2.2.2.4.1 of SRP-LR, Rev. 1.

SRP-LR Section 3.5.2.2.2.4.1 states that increase in porosity and permeability, cracking, loss of material (spalling, scaling)/ aggressive chemical attack; and cracking, loss of bond, and loss of material (spalling, scaling)/ corrosion of embedded steel could occur in below-grade inaccessible concrete areas of Group 6 structures (T-18, T-19). The GALL Report recommends further evaluation of plant-specific programs to manage these aging effects in inaccessible areas if the environment is aggressive. The acceptance criteria are described in Branch Technical Position RLSB-1 (Appendix A.1 of this SRP-LR).

In Attachment 3, Item T-18, of its reconciliation document, the applicant stated that there is no change required to the Oyster Creek LRA due to this item change. The applicant stated that Oyster Creek has committed to inspecting inaccessible areas of structures in the scope of license renewal that are exposed by excavation for any reason, and to sample and test groundwater periodically during the period of extended operation. This line item has been invoked for water control structures. Oyster Creek has committed to performing a baseline inspection of submerged water control structures prior to entering the period of extended operation. A second inspection will be performed 6 years after the baseline inspection. A third inspection will be performed 8 years after the second inspection. Following each inspection, the identified degradations will be evaluated to determine if more frequent inspections are warranted or there is a need for corrective actions to ensure that age related degradations are adequately managed. Inspections will be conducted in accordance with the RG 1.127, inspection of water-control structures associated with nuclear power plants program.

The applicant further stated that the review of design and construction documents indicated that the specified air content is 4 to 6 percent. Water-to-cement ratio was based on the strength required by the design considering the maximum slump of four inches. Curves representing the relation between the water content and the average 28-day compressive strength were established for a range of values including the compressive strengths specified. The curves were established by at least three points, each point represented average values from at least four test specimens. The maximum allowable water content for each class of concrete was determined from the curves and corresponded to a compressive strength of 15 percent greater than that specified for that class of concrete. A review of documentation for a sample of class 4LA (4000 psi) concrete cylinder tests shows that the 28-day strength meets or exceeds the specified 4000 psi compressive strength.

The applicant stated that inspections conducted in accordance with RG 1.127, Inspection of water-control structures associated with nuclear power plants have identified cracking, change in material properties, and loss of material (spalling, scaling), which could be attributed to corrosion of embedded steel in accessible areas. Engineering evaluation of the identified cracking, change in material properties, and loss of material concluded it is not significant to impact the intended function of the affected structure.

Based on above evaluation, the applicant concluded that cracking, change in material properties, and loss of material due to corrosion of embedded steel is not significant for accessible and inaccessible areas, and RG 1.127, inspection of water-control structures associated with nuclear power plants will adequately manage the aging effect. Thus, a plant-specific aging management program is not required.

The project team concurred with the applicant's assessment that the RG 1.127, inspection of water-control structures associated with nuclear power plants program will adequately manage the aging effects that may be caused by corrosion of embedded steel, and that a plant-specific program is not necessary.

In Attachment 3, Item T-19 of its reconciliation document, the applicant stated that there is no change required to the Oyster Creek LRA due to this item change. The applicant stated that Oyster Creek has committed to inspecting inaccessible areas of structures in the scope of license renewal that are exposed by excavation for any reason, and to sample and test groundwater periodically during the period of extended operation. This line item has been invoked for water control structures. Oyster Creek has committed to performing a baseline inspection of submerged water control structures prior to entering the period of extended operation. A second inspection will be performed 6 years after the baseline inspection. A third inspection will be performed 8 years after the second inspection. Following each inspection, the identified degradations will be evaluated to determine if more frequent inspections are warranted or there is a need for corrective actions to ensure that age related degradations are adequately managed. Inspections will be conducted in accordance with RG 1.127, inspection of water-control structures associated with nuclear power plants.

The applicant further stated that inspections conducted in accordance with RG 1.127, inspection of water-control structures associated with nuclear power plants have identified concrete degradation, which could be attributed to aggressive chemical attack in accessible areas. Engineering evaluation of the identified increase in porosity and permeability, cracking, and loss of material concluded it is not significant to impact the intended function of the affected structure.

Based on above evaluation, the applicant concluded that change in material properties, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack is not significant for accessible and inaccessible areas, and RG 1.127, inspection of water-control structures associated with nuclear power plants will adequately manage the aging effect. Thus, a plant-specific aging management program is not required.

The project team concurred with the applicant's assessment that the RG 1.127 inspection of water-control structures associated with nuclear power plants program will adequately manage the aging effects that may be caused by aggressive chemical attack, and that a plant-specific program is not necessary.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.4.1 for further evaluation.

3.5.2.2.2.4.2 Aging Management of Inaccessible Areas for Group 6 Structures [Item 2]

In the OCGS LRA, the applicant addressed further evaluations in accordance with the January 2005 Draft Revision of the SRP-LR. The applicant provided its reconciliation to the further evaluations listed in the September 2005 Revision 1 of the SRP-LR in Attachment 3, Item T-15 of its reconciliation document. The project team reviewed the reconciliation document against the criteria in Section 3.5.2.2.2.4.2 of SRP-LR, Rev. 1.

SRP-LR Section 3.5.2.2.2.4.2 states that loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade inaccessible concrete areas of Group 6 structures (T-15). The GALL Report recommends further evaluation of this aging effect for inaccessible areas for plants located in moderate to severe weathering conditions.

In Attachment 3, Item T-15 of its reconciliation document, the applicant stated that there is no change required to the Oyster Creek LRA due to this item change. The applicant stated that for inaccessible areas, as described in the UFSAR Section 3.8.4.6, ?Materials, Quality Control and Special Construction Techniques", concrete is designed consistent with ACI 318 requirements to provide workable concrete of homogeneous structure which, when hardened, will have durability, impermeability and the specified strength. Testing of concrete was performed in accordance with ASTM Standards specified in ACI 318 to ensure the desired quality of concrete is furnished. The strength quality of the concrete was established by tests made in advance of the beginning of operations using a maximum slump of four inches. Specimens were tested and cured in accordance with ASTM C39.

The applicant further stated that inspections conducted in accordance with the Oyster Creek RG. 1.127, inspection of water-control structures associated with nuclear power plants have identified loss of material (spalling, scaling) and cracking which could be attributed to freeze-thaw in accessible areas. Engineering evaluation of the identified loss of material and cracking concluded it is not significant to impact the intended function of the affected structure.

The applicant concluded that loss of material and cracking due to freeze-thaw is not significant for inaccessible concrete areas of Group 6 structures, and that a plant-specific aging management program is not required.

The project team noted that the applicant's RG. 1.127, inspection of water-control structures associated with nuclear power plants program is credited for managing loss of material, cracking, and change in material properties in both accessible and inaccessible (submerged) concrete areas of Group 6 structures, regardless of the aging mechanism. Any degradation that may be caused by freeze-thaw will be identified. The project team concurred with the applicant's conclusion that a plant-specific program is not needed.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.4.2 for further evaluation.

3.5.2.2.2.4.3 Aging Management of Inaccessible Areas for Group 6 Structures [Item 3]

In the OCGS LRA, the applicant addressed further evaluations in accordance with the January 2005 Draft Revision of the SRP-LR. The applicant provided its reconciliation to the further evaluations listed in the September 2005 Revision 1 of the SRP-LR in Attachment 3, Items T-16 and T-17 of its reconciliation document. The project team reviewed the reconciliation document against the criteria in Section 3.5.2.2.2.4.3 of SRP-LR, Rev. 1.

SRP-LR Section 3.5.2.2.2.4.3 states that cracking due to expansion and reaction with aggregates and increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide could occur in below-grade inaccessible reinforced concrete areas of Group 6 structures (T-16, T-17). The GALL Report recommends further evaluation of inaccessible areas if concrete was not constructed in accordance with the recommendations in ACI 201.2R-77.

In Attachment 3, Items T-16 and T-17 of its reconciliation document, the applicant stated that there is no change required to the Oyster Creek LRA due to this item change. The applicant stated that the Oyster Creek LRA commitment to perform inspections in accordance with RG 1.127 does not change. The applicant further stated that as described in the UFSAR Section 3.8.4.6, ?Materials, Quality Control and Special Construction Techniques", the cement used for Oyster Creek was an approved brand of Portland Cement conforming to ASTM Specification C-150; Type II, low alkali. Alkali content is limited to 0.6 percent total alkali. The low alkali requirement for the cement was waived, provided petrographic tests conducted in accordance with ASTM C295 and C227 demonstrated no potential alkali reactivity for all aggregates proposed for use. This provides assurance that aggregates do not react with reinforced concrete.

The applicant further stated that the aggregate used on the project was from approved sources and consisted of clean, hard, durable particles conforming to the requirements of concrete specifications. Tests were performed as necessary to determine that the proposed aggregate would produce concrete of acceptable quality and durability, meeting ACI recommendations.

The project team concurred with the applicant's assessment of cracking due to expansion and reaction with aggregates. The project team also noted that the applicant's RG. 1.127 inspection of water-control structures associated with nuclear power plants program is credited for managing loss of material, cracking, and change in material properties in both accessible and inaccessible (submerged) concrete areas of Group 6 structures, regardless of the aging mechanism. Any degradation that may be caused by these aging mechanisms will be identified.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.4.3 for further evaluation.

3.5.2.2.2.5 Cracking Due to Stress Corrosion Cracking and Loss of Material Due to Pitting and Crevice Corrosion

In the OCGS LRA Table3.5.1, Item Number 3.5.1-30, the applicant indicated that cracking due to stress corrosion cracking or loss of material due to pitting and crevice corrosion for Group 7 and 8 stainless steel tank liners is not applicable. The applicant stated that the only stainless steel lined concrete tank at Oyster Creek is the spent fuel pool surge tank. Aging effects of the stainless steel tank liner are evaluated with the mechanical auxiliary systems.

SRP-LR Section 3.5.2.2.2.5 states that the GALL Report recommends further evaluation of plant-specific programs to manage cracking due to SCC and loss of material due to pitting and crevice corrosion for stainless steel tank liners exposed to standing water. The reviewer reviews the applicant's proposed aging management program on a case-by-case basis to ensure that the intended functions will be maintained during the period of the extended operation.

The project team reviewed Tables 3.5.2.1.1 through 3.5.2.1.19 in the OCGS LRA, and noted that the only stainless steel tank liner listed is the fuel pool skimmer surge tank liner, in Table 3.5.2.1.2. The AMR for this tank references GALL Table 2 item VII.A4-11 and Table 1 item 3.3.1-22, in auxiliary systems. The water chemistry and one-time inspection programs are credited for aging management. The project team determined that the applicant's aging management program for the stainless steel tank liner is acceptable.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.6 for further evaluation.

3.5.2.2.2.6 Aging of Supports Not Covered by Structures Monitoring Program

In the OCGS LRA, the applicant addressed further evaluations in accordance with the January 2005 Draft Revision of the SRP-LR. No further evaluation was required because all supports (other than ASME Class supports) are covered by the structures monitoring program. The applicant provided its reconciliation to the further evaluations listed in the September 2005 Revision 1 of the SRP-LR in Attachment 3, Items T-29, T-30, and T-31 of its reconciliation document. The project team reviewed the reconciliation document against the criteria in Section 3.5.2.2.2.6 of SRP-LR, Rev. 1.

SRP-LR Section 3.5.2.2.2.6 states that the GALL Report recommends further evaluation of certain component support/aging effect combinations if they are not covered by the structures monitoring program. This includes (1) loss of material due to general and pitting corrosion, for Groups B2-B5 supports (T-30); (2) reduction in concrete anchor capacity due to degradation of the surrounding concrete, for Groups B1-B5 supports (T-29); and (3) reduction/loss of isolation function due to degradation of vibration isolation elements, for Group B4 supports (T-31). Further evaluation is necessary only for structure/aging effect combinations not covered by the structures monitoring program.

In Attachment 3, Item T-29 of its reconciliation document, the applicant stated that there is no change required to the Oyster Creek LRA due to this item change. The wording for further evaluation was changed from not required if within the scope of the applicant's structures monitoring program, to required if not within the scope of the applicant's structures monitoring program. This item is within the scope of Oyster Creek's structures monitoring program, therefore further evaluation is not required.

The project team concurred with the applicant's assessment.

In Attachment 3, Item T-30 of its reconciliation document, the applicant stated that there is no change required to the Oyster Creek LRA due to this item change. The wording for further evaluation was changed from not required if within the scope of the applicant's structures monitoring program, to required if not within the scope of the applicant's structures monitoring program. This item is within the scope of Oyster Creek's structures monitoring program, therefore further evaluation is not required.

The project team concurred with the applicant's assessment.

Attachment 3, Item T-31 of its reconciliation document, the applicant stated that there is no change required to the Oyster Creek LRA due to this item change. The wording for further evaluation was changed from not required if within the scope of the applicant's structures monitoring program, to required if not within the scope of the applicant's structures monitoring program. This item is within the scope of Oyster Creek's Structures Monitoring Program, therefore further evaluation is not required.

The project team concurred with the applicant's assessment.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.5.2.2.2.6 for further evaluation.

3.5.2.2.2.7 <u>Cumulative Fatigue Damage Due to Cyclic Loading</u>

In LRA Section 3.5.2.2.3 (2), the applicant stated that fatigue of support members, anchor bolts, and welds for Groups B1.1, B1.2, and B1.3 component supports is a TLAA as defined in 10 CFR 54.3 only if a CLB fatigue analysis exists. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). At Oyster Creek, there are no fatigue analyses applicable to Groups B1.1, and B1.2 component supports in the CLB. Therefore, cumulative fatigue damage for Groups B1.1 and B1.2 component supports is not a TLAA as defined in 10 CFR 54.3. The Oyster Creek CLB includes fatigue analysis for certain Group B1.3, ASME Class MC component supports. For these supports (torus support columns and sway braces), cumulative fatigue damage is a TLAA, and is evaluated in accordance with 10 CFR 54.21(c), in LRA Section 4.6.1.

The NRR/DE staff reviewed this TLAA, and its evaluation is documented separately in Section 4 of the SER related to the OCGS LRA.

3.5.2.2.3 <u>Quality Assurance for Aging Management of Non-Safety-Related Components</u>

OCGS LRA Section 3.5.2.2.3 is reviewed by NRR staff and will be addressed separately in Section 3 of the SER related to the OCGS LRA.

<u>Conclusion</u>

The project team evaluated the degradation history of the OCGS containment and the adequacy of the applicant's aging management commitments for the extended period of operation in its evaluation of the applicant's IWE aging management program (B.1.27). Three significant audit open items have been identified. See 3.0.3.2.22 of this audit report.

3.5.2.3 *AMR Results That Are Not Consistent With The GALL Report Or Not Addressed In The GALL Report*

<u>Summary of Information in the Application</u>

In OCGS LRA Table 3.5.1, Summary of Aging Management Evaluations for the Primary Containment, Structures, Component Supports, and Piping and Component Insulation, the applicant provided information regarding components or material/environment combination in the GALL Report that it evaluated and identified as not applicable to its plant.

In OCGS LRA Tables 3.5.2.1.1 through 3.5.2.1.19, the applicant provided additional details of the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that are not consistent with the GALL Report. Specifically, the applicant indicated, via Notes F through J, that neither the identified component nor the material/environment combination is evaluated in the GALL Report and provided information concerning how the aging effect requiring management will be managed.

Project Team Evaluation

The project team did not review the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that are not consistent with the GALL Report or are not addressed in the GALL Report. These AMR line items were reviewed by NRR/DE staff, and are discussed in the SER related to the OCGS LRA.

3.5.3 Conclusion

Three significant audit open items have been identified. See 3.0.3.2.22 of this audit report.

The project team also reviewed the applicable UFSAR supplement program summaries and concluded that the applicant needs to update the UFSAR based on commitments specified in applicant's letters dated April 4, 2006, April 17, 2006, May 1, 2006, and resolutions to open items discussed in Section 3.0.3.2.22 of this report.

3.6 OCGS LRA Section 3.6 – Aging Management of Electrical Components

This section of the audit and review report documents the project team's review and evaluation of OCGS AMR results for the aging management of the electrical component and component groups associated with (1) insulated cables and connections, (2) electrical penetrations, (3) high-voltage insulators, (4) transmission conductors and connections, (5) fuse holders, (6) wooden utility poles, (7) cable connections (metallic parts), and (8) uninsulated ground conductors.

3.6.1 Summary of Technical Information in the Application

In the OCGS LRA Section 3.6, the applicant provided the results of its AMRs for the electrical components and component groups.

In Table 3.6.1 of the OCGS LRA, the applicant provided a summary comparison of its AMR line items with the AMR line items evaluated in the GALL Report for the electrical components and component groups. For each component type in the table, the applicant identified those components that are consistent with the GALL Report, those for which the GALL Report recommends further evaluation, and those components that are not addressed in the GALL Report, together with the basis for their exclusion.

In Tables 3.6.2.1.1 and 3.6.2.1.2 of the OCGS LRA, the applicant provided a summary of the AMR results for component types associated with (1) insulated cables and connections, (2) electrical penetrations, (3) high-voltage insulators, (4) transmission conductors and connections, (5) fuse holders, (6) wooden utility poles, (7) cable connections (metallic parts), and (8) uninsulated ground conductors. Specifically, the information for each component type included the intended function, material, environment, aging effect requiring management (AERM), AMPs, the GALL Report Volume 2 item, cross-reference to Table 3.6.1 of the OCGS LRA (Table 1), and generic and plant-specific notes related to consistency with the GALL Report.

The applicant's AMRs incorporated applicable operating experience in the determination of AERMs. These reviews included evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.6.2 Project Team Evaluation

The project team reviewed Section 3.6 of the OCGS LRA to determine if the applicant provided sufficient information to demonstrate that the effects of aging for the electrical components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The project team reviewed certain identified AMR line items to confirm the applicant's claim that these AMR line items were consistent with the GALL Report. The project team did not repeat its review of the matters described in the GALL Report. However, the project team did verify that the material presented in the OCGS LRA was applicable and that the applicant had identified the appropriate GALL Report AMR line items. The project team's audit evaluation is documented in Section 3.6.2.1 of this audit and review report. In addition, the project team's evaluations of the AMPs are documented in Section 3.0.3 of this audit and review report.

The project team reviewed those selected AMR line items for which further evaluation is recommended by the GALL Report. The project team confirmed that the applicant's further evaluations were in accordance with the acceptance criteria in the SRP-LR. The project team's audit evaluation is documented in Section 3.6.2.2 of this audit and review report.

The project team also reviewed of the remaining AMR line items that were not consistent with or not addressed in the GALL Report based on NRC-approved precedents. The audit included evaluating whether all plausible aging effects were identified and whether the aging effects listed were appropriate for the combination of materials and environments specified. The project team's evaluation is documented in Section 3.6.2.3 of this audit and review report.

Finally, the project team reviewed the AMP summary descriptions in the UFSAR Supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the electrical components.

Table 3.6-1 below provides a summary of the project team's evaluation of components, aging effects/aging mechanisms, and AMPs listed in Section 3.6 of the OCGS LRA that are addressed in the GALL Report. It also includes the section of the audit and review report in which the project team's evaluation is documented.

Table 3.6-1 Staff Evaluation for Electrical Components in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Electrical equipment subject to 10 CFR 50.49 environmental qualification (EQ) requirements (Item 3.6.1-1)	Degradation due to various aging mechanisms	Environmental Qualification of Electric Components	TLAA	Consistent with GALL, which recommends further evaluation (See SER Section 4.4)
Electrical cables, connections and fuse holders (insulation) not subject to 10 CFR 50.49 EQ requirements (Item 3.6.1-2)	Reduced insulation resistance and electrical failure due to various physical, thermal, radiolytic, photolytic, and chemical mechanisms	Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program, B.1.34.	Consistent with GALL (See Audit Report Section 3.6.2.1)
Conductor insulation for electrical cables and connections used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements that are sensitive to reduction in conductor insulation resistance (IR) (Item 3.6.1-3)	Reduced insulation resistance and electrical failure due to various physical, thermal, radiolytic, photolytic, and chemical mechanisms	Electrical Cables And Connections Used In Instrumentation Circuits Not Subject To 10 CFR 50.49 EQ Requirements	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used In Instrumentation Circuits program, B.1.35	Consistent with GALL (See Audit Report Section 3.6.2.1)
Conductor insulation for inaccessible medium voltage (2 kV to 35 kV) cables (e.g., installed in conduit or direct buried) not subject to 10 CFR 50.49 EQ requirements (Item 3.6.1-4)	Localized damage and breakdown of insulation leading to electrical failure due to moisture intrusion, water trees	Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements	Inaccessible Medium Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements program, B.1.36	Consistent with GALL (See Audit Report Section 3.6.2.1)
Fuse Holders (Not Part of a Larger Assembly): Fuse holders – metallic clamp (Item 3.6.1-6)	Fatigue due to ohmic heating, thermal cycling, electrical transients, frequent manipulation, vibration, chemical contamination, corrosion, and oxidation	Fuse Holders	None	NUREG-1801 aging effect is not applicable to Oyster Creek. (See evaluation by DE)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Metal enclosed bus - Bus/ Connections (Item 3.6.1-7)	Loosening of bolted connections due to thermal cycling and ohmic heating	Metal Enclosed Bus	None	Not Applicable. Oyster Creek has no phase bus in the scope of license renewal. (See evaluation by DE)
Metal enclosed bus - Insulation/ Insulators (Item 3.6.1-8)	Reduced insulation resistance and electrical failure due to various physical, thermal, radiolytic, photolytic, and chemical mechanisms	Metal Enclosed Bus	None	Not Applicable. Oyster Creek has no phase bus in the scope of license renewal. (See evaluation by DE)
Metal enclosed bus - Enclosure assemblies (Item 3.6.1-9)	Loss of material due to general corrosion	Structures Monitoring Program	N/A	Not Applicable. Oyster Creek has no phase bus in the scope of license renewal. (See evaluation by DE)
Metal enclosed bus - Enclosure assemblies (Item 3.6.1-10)	Hardening and loss of strength due to elastomers degradation	Structures Monitoring Program	N/A	Not Applicable. Oyster Creek has no phase bus in the scope of license renewal. (See evaluation by DE)
High voltage insulators (Item 3.6.1-11)	Degradation of insulation quality due to presence of any salt deposits and surface contamination; Loss of material caused by mechanical wear due to wind blowing on transmission conductors	A plant-specific aging management program is to be evaluated	None	Consistent with GALL, which recommends further evaluation (Evaluation by DE)
Transmission conductors and connections; switchyard bus and connections (Item 3.6.1-12)	Loss of material due to wind induced abrasion and fatigue; loss of conductor strength due to corrosion; increased resistance of connection due to oxidation or loss of preload	A plant-specific aging management program is to be evaluated	None	Consistent with GALL, which recommends further evaluation. NUREG-1801 aging effect is not applicable to Oyster Creek. (Evaluation by DE)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Cable Connections - Metallic parts (Item 3.6.1-13)	Loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation	Electrical Cable Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements	None	NUREG-1801 aging effect is not applicable to Oyster Creek. (Evaluation by DE).
Fuse Holders (Not Part of a Larger Assembly) Insulation material (Item 3.6.1-14)	None	None	None	Not Applicable

3.6.2.1 *AMR Results That Are Consistent with The GALL Report*

Summary of Information in the Application

For aging management evaluations that the applicant stated are consistent with the GALL Report, the project team conducted its audit and review to determine if the applicant's reference to the GALL Report in the OCGS LRA is acceptable.

In OCGS LRA Section 3.6.2.1, the applicant identified the materials, environments, and aging effects requiring management. The applicant identified the following programs that manage the aging effects related to the insulated cables and connections:

- Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements (B.1.34)
- Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrument Circuits (B.1.35)
- Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements (B.1.36)

Project Team Evaluation

The project team reviewed its assigned OCGS LRA AMR line items to determine that the applicant (1) provided a brief description of the system, components, materials, and environment, (2) stated that the applicable aging effects have been reviewed and are evaluated in the GALL Report, and (3) identified those aging effects for the insulated cables and connections that are subject to an AMR.

On the basis of its review, the project team found that the applicant appropriately addressed the aging effect/mechanisms, as recommended by the GALL Report.

Conclusion

The project team has evaluated the applicant's claim of consistency with the GALL Report. The project team also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the project team found that the AMR results that the applicant claimed to be consistent with the GALL Report are consistent with the AMRs in the GALL Report.

3.6.2.2 *AMR Results For Which Further Evaluation Is Recommended By The GALL Report*

Summary of Information in the Application

In Section 3.6.2.2 of the OCGS LRA, the applicant provided further evaluation of aging management as recommended by the GALL Report for the insulated cables and connections, electrical penetrations, high-voltage insulators, transmission conductors and connections, fuse holders, wooden utility poles, cable connections (metallic parts), and uninsulated ground conductor components and component groups. The applicant also provided information concerning how it will manage the related aging effects.

Project Team Evaluation

For some AMR line items assigned to the project team in OCGS LRA Table 3.6.1, the GALL Report recommends further evaluation. When further evaluation is recommended, the project team reviewed the evaluations provided in Section 3.6.2.2 of the OCGS LRA against the criteria provided in Section 3.6.2.2 of the SRP-LR. The project team's assessments of these evaluations is documented in this section. These assessments are applicable to each Table 2 AMR line item in Section 3.6 citing the item in Table 1.

3.6.2.2.1 Electrical Equipment Subject to Environmental Qualification

The project team reviewed OCGS LRA Section 3.6.2.2.1 against the criteria in SRP-LR Section 3.6.2.2.1.

SRP-LR Section 3.6.2.2.1 stated that environmental qualification (EQ) is a TLAA as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c).

OCNGS LRA Section 3.6.2.2.1 stated that EQ is a time-limited aging analysis (TLAA) as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The evaluation of this TLAA will be addressed separately in Section 4 of the SER related to the OCGS LRA.

3.6.2.2.2 Degradation of Insulator Quality Due to Presence of Any Salt Deposits and Surface Contamination, and Loss of Material Due to Mechanical Wear

Section 3.6.2.2.2 is reviewed by NRR/DE staff.

3.6.2.2.3 Loss of Material Due to Wind Induced Abrasion and Fatigue, Loss of Conductor Strength Due to Corrosion, an Increased Resistance of Connection Due to Oxidation or Loss of Pre-load

Section 3.6.2.2.3 is reviewed by NRR/DE staff.

3.6.2.2.4 Quality Assurance for Aging Management of Non-Safety-Related Components

Section 3.6.2.2.4 is reviewed by NRR/DE staff.

Conclusion

On the basis of its review, for component groups evaluated in the GALL Report for which the GALL Report recommends further evaluation, the project team determined that these further evaluations will be reviewed by the NRR/DE staff, and will be documented in the SER related to the OCGS LRA.

3.6.2.3 *AMR Results That Are Not Consistent With The GALL Report Or Not Addressed In The GALL Report*

Section 3.6.2.3 is reviewed by NRR/DE staff.

3.6.3 Conclusion

On the basis of its review, the project team determined that the applicant has demonstrated that the aging effects associated with the electrical components will be adequately managed.

The project team also reviewed the applicable UFSAR supplement program summaries and concludes that they adequately describe the AMPs credited for managing aging of electrical components, as required by 10 CFR 54.21(d).

ATTACHMENT 1: LIST OF ABBREVIATIONS

ACI	American Concrete Institute
ADAMS	Agencywide Documents Access and Management System
AMP	aging management program
AMR	aging management review
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing Materials
BNL	Brookhaven National Laboratory
BTP	Branch Technical position
BWR	boiling water reactor
BWRVIP	Boiling Water Reactor Vessel Improvement Program
C	Celsius
CASS	cast austenitic stainless steel
CFR	Code of Federal Regulations
CLB	current licensing basis
DE	Division of Engineering
DIPM	Division of Inspection Program Management
DSSA	Division of Systems Safety and Analysis
EDG	emergency diesel generator
EPRI	Electric Power Research Institute
ESF	engineered safety features
EQ	environmental qualification
F	Fahrenheit
FAC	flow-accelerated corrosion
FSAR	Final Safety Analysis Report
GALL	Generic Aging Lessons Learned
GL	Generic Letter
GSI	Generic Safety Issue
I&C	instrumentation and control
IASCC	irradiation assisted stress corrosion cracking
IGSCC	intergranular stress corrosion cracking
IN	Information Notice
INPO	Institute of Nuclear Power Operations
ISG	Interim Staff Guidance
ISI	inservice inspection
LER	licensee event report
LRA	license renewal application
MIC	microbiologically influenced corrosion
n/cm^2	neutrons per square centimeter
NDE	nondestructive examination
NEI	Nuclear Energy Institute
NPS	nominal pipe size
NRC	U.S. Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NUMARC	Nuclear Management and Resources Council
NUREG	Nuclear Regulatory Commission technical report
OCGS	Oyster Creek Generating Station
ppm	parts per million
PWR	pressurized water reactor
RAI	request for additional information

RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RG	Regulatory Guide
RLEP-B	License Renewal and Environmental Impacts Program, Section B
RLSB	License Renewal and Standardization Branch
SBO	station blackout
SCC	stress corrosion cracking
SC	structures and components
SER	Safety Evaluation Report
SLC	standby liquid control
SRP-LR	Standard Review Plan-License Renewal
SSC	structure, system, and component
SW	service water
TLAA	time-limited aging analysis
UFSAR	Updated Final Safety Analysis Report

ATTACHMENT 2: PROJECT TEAM AND APPLICANT PERSONNEL; PUBLIC EXIT MEETING ATTENDEES

Project Team

G. Cranston/Roy Mathew, NRC, Team Leader
J. Davis, NRC, Reviewer – Mechanical
R. Mathew, NRC, Reviewer – Electrical
D. Hoang, NRC, Reviewer – Structural
R. Morante, BNL, Lead Reviewer – Mechanical, Materials, Structural
M. Subudhi, BNL, Reviewer – Materials, Mechanical
R. Lofaro, BNL, Reviewer – Systems, Mechanical
K. Sullivan, BNL, Reviewer – AMPs, Systems, Fire Protection
M. Villaran, BNL, Reviewer – Systems, Fire Protection, Mechanical
B. Johanson, Aerotek, Administrative Support

Project Team Support

K. Chang, NRC, Chief, RLEP Section C
D. Ashley, NRC, OCGS License Renewal Project Manager

Applicant Personnel

R. Artz, Subject Matter Expert, Fuel Oil Chemistry
L. Corsi, License Renewal Team Engineer
M. Gallagher, Exelon Vice President, License Renewal
S. Getz, License Renewal Team Engineer
G. Harttraft, Subject Matter Expert, Mechanical Systems ISI
D. Honan, License Renewal Team Engineer
J. Hufnagel, NRC Interface/Licensing Lead
M. May, License Renewal Team Engineer
C. Micklo, License Renewal Team Engineer
M. Miller, License Renewal Team Engineer
K. Muggleston, License Renewal Team Engineer
A. Ouaou, License Renewal Team Engineer
F. Polaski, License Renewal Manager
T. Quintenz, Site Lead License Renewal Engineer
S. Raffertya, License Renewal Team Engineer
R. Skelsky, Subject Matter Expert, EDG System
D. Warfel, Oyster Creek License Renewal Technical Lead

Attendees at the Public Exit Meeting on April 20, 2006

Name	**Organization**
Donnie J. Ashley	NRC
Louise Lund	NRC
Ann Hodgdon	NRC
Ken Chang	NRC
Roy Mathew	NRC
James Davis	NRC
Hans Ashar	NRC
Ron Bellamy	NRC
Diane Screnci	NRC
Marvin Sykes	NRC
Rich Morante	Brookhaven National Laboratory
Jennifer Sneed	Office of Senator Frank R. Lautenberg
Joan Richards	Office of Congressman Jim Saxton
Richard Pinney	New Jersey DEP
Ron Zak	New Jersey DEP
David Most	Lacey Township
Joseph Scarpelli	Mayor-Brick Township
Bud Swenson	Exelon/AmerGen/Oyster Creek
Tim Rausch	Exelon/AmerGen/Oyster Creek
Mike Galagher	Exelon/AmerGen/Oyster Creek
Don Warfel	Exelon/AmerGen/Oyster Creek
John G. Hufnagel	Exelon/AmerGen/Oyster Creek
Cindy Connelly	Exelon/AmerGen/Oyster Creek
Wayne Romberg	Exelon/AmerGen/Oyster Creek
Jim Laird	Exelon/AmerGen/Oyster Creek
Pete Resler	Exelon/AmerGen/Oyster Creek
Rachelle Benson	Exelon/AmerGen/Oyster Creek
Vinod Aggarwal	Exelon/AmerGen/Oyster Creek
Howie Ray	Exelon/AmerGen/Oyster Creek
***	Exelon/AmerGen/Oyster Creek
George Rossi	IBEW LU 400
Guy Peterson	IBEW LU 400
Ed Stroup	IBEW LU 1289
Paula Gotsch	GRAMMES
Jeffery Brown	GRAMMES
Janet Tavro	GRAMMES
Jane R. DeMarzo	GRAMMES
Gail Marsh Saxer	League of Women Voters
Sandra Potasles	LWV
Joan Rubin	LWV
Barbara Bailine	LWV
Donald Warren	Jersey Shore Nuclear Watch

Name	**Organization**
***	JSNW
***	JSNW
Kelly McNicholas	Sierra Club
Suzanne Leta	NJPIRG
Steve Healey	OCSD-OEM
Paul Gunter	NIRS
Peggi Sturmfels	NJE Federation
Tony DeMarzo	MBC
Michele Donato	Mayor Scarpelli
Ed Frydendahl	Manchester Resident
Regina Discenza	Resident
William Stockles	Resident
Sandra Brown	Resident
Howard Schwartz	Resident
Monty Williamson	Local
Joanie M. Parks	Waretown Resident
George Chowerna	Taxpayer
***	Times – Beacon Newspapers
Nicholas Clunn	Asbury Park Press
Tom Mongelli	Millennium Radio
Bill Murray	none listed
Eugene Creamer	none listed

*** Name not legible

ATTACHMENT 3: AGING MANAGEMENT PROGRAM ELEMENT DESCRIPTIONS

Element	Description
1. Scope of the Program	The scope of the program should include the specific structures and components subject to an aging management review.
2. Preventive Actions	Preventive actions should mitigate or prevent the applicable aging effects.
3. Parameters Monitored or Inspected	Parameters monitored or inspected should be linked to the effects of aging on the intended functions of the particular structure and component.
4. Detection of Aging Effects	Detection of aging effects should occur before there is loss of any structure and component intended function. This includes aspects such as method or technique (i.e., visual, volumetric, surface inspection), frequency, sample size, data collection and timing of new/one-time inspections to ensure timely detection of aging effects.
5. Monitoring and Trending	Monitoring and trending should provide prediction of the extent of the effects of aging and timely corrective or mitigative actions.
6. Acceptance Criteria	Acceptance criteria, against which the need for corrective action will be evaluated, should ensure that the particular structure and component intended functions are maintained under all current licensing basis design conditions during the period of extended operation.
7. Corrective Actions	Corrective actions, including root cause determination and prevention of recurrence, should be timely.
8. Confirmation Process	The confirmation process should ensure that preventive actions are adequate and appropriate corrective actions have been completed and are effective.
9. Administrative Controls	Administrative controls should provide a formal review and approval process.
10. Operating Experience	Operating experience involving the aging management program, including past corrective actions resulting in program enhancements or additional programs, should provide objective evidence to support a determination that the effects of aging will be adequately managed so that the structure and component intended functions will be maintained during the period of extended operation.

ATTACHMENT 4: SUMMARY OF LRA AUDIT OPEN ITEMS

During the audit and review, the project team identified the following open items. These open items represent issues identified during the audit and review of the Oyster Creek license renewal application that could not be resolved as part of the audit, and were forwarded to the NRC staff for resolution.

Open Item No.	Description
3.0.3.2.22-1	The project team found that the absence of a leakage monitoring program to meet the current license term commitment raises a question about the basis for the applicant's claim that water is no longer leaking into the annular gap between the drywell shell and the concrete shield wall. The project team identified the review of applicant information that confirms the absence of water leakage into the annular gap between the drywell shell and the concrete shield wall as Open Item 3.0.3.2.22-1.
3.0.3.2.22-2	However, because there has been no UT inspection conducted since 1996 and the remaining corrosion margin in 1996 was less than 0.1" at several locations, the project team initiated further evaluation of the applicant's aging management commitment for UT inspection of the former sand bed region. The project team identified the review of applicant information that confirms the drywell shell in the former sand bed region has the minimum required thickness to ensure no loss of intended function during the extended period of operation as Open Item 3.0.3.2.22-2.
3.0.3.2.22-3	Because of the minimal corrosion margin remaining in the former sand bed region, and the applicant's reliance on the coating to mitigate additional corrosion, the project team initiated further review of the applicant's inspection program to ensure that the coating will continue to perform its intended function for the extended period of operation. The project team identified the review of applicant information that confirms the drywell shell in the former sand bed region has the minimum required thickness and that coating and inspections are adequate to ensure no loss of intended function during the extended period of operation as Open Item 3.0.3.2.22-3.

ATTACHMENT 5: LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed by the project team as part of the audit and review of the OCGS LRA. Inclusion of a document on this list does not imply that the project team reviewed the entire document; rather, selected sections or portions of the documents were reviewed as part of the overall effort documented in this audit and review report. In addition, inclusion of a document in this list does not imply NRC acceptance of the document.

Applicant's Aging Management Program	**GALL Report Aging Management Program**	**LRA-AMP Basis Document and Other Documents Reviewed**
Oyster Creek Generating Station (OCGS) AMPs		
ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.1.1)	XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Focused Area Self-Assessment (FASA) Report, ?Oyster Creek ISI Program," April 26-29, 2004. Oyster Creek OC-1 Program Plan, ?OCGS ISI Program Plan Fourth Ten-Year Inspection Interval," Rev. 1, 09/30/2004 OCGS Implementing Procedure TQ-AA-122, ?Qualification and Certification of Nondestructive (NDE) Personnel," Rev. 1, undated OCGS Implementing Procedure ER-AA-335-025, ?Oversight of Vendor NDE Activities," Rev. 1, undated OCGS NIS-1 Inservice Inspection Data Report from 1R19 Refueling Outage, January 22, 2003 OCGS NIS-1 Inservice Inspection Data Report from 1R20 Refueling Outage, February 16, 2005 PBD-AMP-B.1.01, ?OCGS Program Basis Document ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," Rev. 0, 11/28/2005 Exelon Nuclear Procedure ER-AA-330, ?Conduct of Inservice Inspection Activities," Rev. 4, undated
Water Chemistry (B.1.2)	XI.M2, Water Chemistry	plant-specific AMPBWRVIP-130, ?BWR Vessel and Internals Project: BWR Water Chemistry Guidelines – 2004 Revision," EPRI TR-1008192, Final Report, October 2004 BWRVIP-79, ?BWR Vessel and Internals Project: BWR Water Chemistry Guidelines – 2000 Revision," EPRI TR-103515-R2, Final Report, March 2000 BWRVIP-29, ?BWR Vessel and Internals Project: BWR Water Chemistry Guidelines – 1996 Revision," EPRI TR-103515-R1, Final Report, December 1996 NEI 03-08, ?Guideline for the Management of Materials Issues," May 2003 OCGS Implementing Procedure CY-AB-120-1000, ?BWR

Applicant's Aging Management Program	GALL Report Aging Management Program	LRA-AMP Basis Document and Other Documents Reviewed
		Chemistry Optimization," Rev.2 OCGS Implementing Procedure CY-AB-120-1100, ?Reactor Water Hydrogen Water Chemistry, Noble Chem and Zinc Injection," Rev.2 OCGS Implementing Procedure CY-AB-120-100, ?Reactor Water Chemistry," Rev.7 OCGS Implementing Procedure CY-AB-120-110, ?Condensate and Feedwater Chemistry," Rev.7 OCGS Report, ?Focus Area Self-Assessment Report," 4/13 – 4/16, 2004 PBD-AMP-B.1.02, ?Water Chemistry," Rev. 0, dated 11-22-2005.
Reactor Head Closure Studs (B.1.3)	XI.M3, Reactor Head Closure Studs	PBD-AMP-B.1.03, ?Reactor Head Closure Studs Oyster Creek Generating Station," Rev. 0, 12/08/2005 OC-1, ?ISI Program Plan Fourth Ten-year inspection Interval," Rev. 1, 9/30/04 Drawing CE 232-573, "Stud, Nut, Washer, & Bushing Detail," Rev. 10 Certified Material Test Report (CMTR), Crucible Steel Company, Piece Number 573-01, Code Number G-385, 8/7/65
BWR Vessel ID Attachment Welds (B.1.4)	XI.M4, BWR Vessel ID Attachment Welds	PBD-AMP-B.1.04, ?BWR Vessel ID Attachment Welds," Rev. 0, 12/07/2005 BWR Vessel Id Attachment welds Oyster Creek Generating Station (implementation procedure), OC-5, ?Program Plan, Reactor Intervals Program," Rev. 0, 09/30/2005
BWR Feedwater Nozzle (B.1.5)	XI.M5, BWR Feedwater Nozzle	NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking," November 1980 GE NE-523-A71-0594-A,"Alternate BWR Feedwater Nozzle Inspection Requirement," Revision 1, August 1999 OC-1, ?OCGS ISI Program Plan for Fourth Ten-Year Inspection Interval," Rev.1, 09/01/2004 Letter P. F. McKee (NRC) to J. J. Barton (GPU), "Evaluation of the Request for Relief From NUREG-0619 for Oyster Creek Nuclear Generating Station (TAC No. M85751)" dated October 4, 1994

Applicant's Aging Management Program	GALL Report Aging Management Program	LRA-AMP Basis Document and Other Documents Reviewed
		Letter A. M. Dromerick (NRC) to J. J. Barton (GPU), "GPU Nuclear Corporation Proposal to Revise NUREG-0619 Regarding the Feedwater Nozzles and Control Rod Drive Return Line Nozzle (TAC No. M83157)," dated July 8, 1992 Drawing MP 1083-87-01, Sheets 1 and 2, "Feedwater Sparger Assembly & Details" DRF 88021, R3, (MDD-OC-422A, R3), "Modification Design Description for Main Feedwater Line Block Valve Addition," November 29, 1989 Letter J. C. Devine to NRC, "Revision to NUREG 0619 Routine Inspection Criteria for Feedwater and Control Rod Drive Return Line Nozzles," September 1, 1992. PBD-AMP-B.1.05," BWR Feedwater Nozzle," Rev. 0, 12/09/2005
BWR Control Rod Drive Return Line Nozzle (B.1.6)	XI.M6, BWR Control Rod Drive Return Line Nozzle	NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking," November 1980 OC-1, ?OCGS ISI Program Plan for Fourth Ten-Year Inspection Interval," Rev. 1, 09/01/2004 Letter P. F. McKee (NRC) to J. J. Barton (GPU), "Evaluation of the Request for Relief From NUREG-0619 for Oyster Creek Nuclear Generating Station (TAC No. M85751)" dated October 4, 1994 Letter A. M. Dromerick (NRC) to J. J. Barton (GPU), "GPU Nuclear Corporation Proposal to Revise NUREG-0619 Regarding the Feedwater Nozzles and Control Rod Drive Return Line Nozzle (TAC No. M83157)" dated July 8, 1992 Drawing GE 921D257, "Control Rod Drive (CRD) Hydraulic System Return Nozzle Safe End Replacement" OCNGSR14-ACRD, "CRDRL Nozzle Inspection (RFO 14)," December 1992 Letter J. C. Devine to NRC, "Revision to NUREG 0619 Routine Inspection Criteria for Feedwater and Control Rod Drive return Line Nozzles," September 1, 1992 Report 990-1743, "Design Report of CRD Return Nozzle Thermal Sleeve Modification," September 1977 OCGS OC-5 Program Plan, ?Reactor Internals Program," Rev. 0, 09/30/2005 PBD-AMP-B.1.6, ?BWR CRD Return Line Nozzle," Rev. 0

Applicant's Aging Management Program	GALL Report Aging Management Program	LRA-AMP Basis Document and Other Documents Reviewed
BWR Stress Corrosion Cracking (B.1.7)	XI.M7, BWR Stress Corrosion Cracking	OC-1, ?OCGS ISI Program Plan for Fourth Ten-Year Inspection Interval," Rev.1, 09/01/2004 NRC GL 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping," U.S. Nuclear Regulatory Commission, January 25, 1988; Supplement 1, February 4, 1992 NUREG-0313,"Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," W. S. Hazelton and W. H. Koo, U.S. Nuclear Regulatory Commission, Rev. 2, 1988 OCGS IGSCC Inspection Program Plan OC-2, "IGSCC Inspection Program (GL 88-01 and BWRVIP-75)," Rev. 0, 07/31/2003 BWRVIP-75, "BWR Vessel and Internals Project: Technical Basis for Revisions to GL 88-01 Inspection Schedule," October 1999 Bateman, W.H., NRC Final SER of the BWRVIP-75, May 14, 2002 ASME Code, Section XI, "Rules for In-service Inspection of Nuclear Plant Components," 1995 Edition through 1996 Addendum OCGS Implementing Procedure ER-AA-330-002, "In-service Inspection of Section XI Welds and Components," Rev. 4 OCGS Implementing Procedure ER-AA-330-009, "ASME Section XI Repair/Replacement Program," Rev. 3 PBD-AMP-B.1.07, "BWR Stress Corrosion Cracking," Rev. 0, 12/19/2005 TR-050, "GPUN Response to GL 88-01 and NUREG 0313, Rev. 2," Rev. 3, 12/17/1990
BWR Penetrations (B.1.8)	XI.M8, BWR Penetrations	BWRVIP-130, "BWR Vessel and Internals Project: BWR Water Chemistry Guidelines – 2004 Revision," EPRI TR-1008192, Final Report, October 2004 BWRVIP-27-A, "BWR Standby Liquid Control System/Core Plate DP Inspection and Flaw Evaluation Guidelines, EPRI TR-107286, July 2003 BWRVIP-49-A, "Instrument Penetration Inspection and Flaw Evaluation Guidelines," EPRI TR-108695, March 2002 OCGS Reactor Internals Program Plan OC-5, "Reactor Internals Program" Rev. 0, 09/30/2005

Applicant's Aging Management Program	GALL Report Aging Management Program	LRA-AMP Basis Document and Other Documents Reviewed
		OCGS Implementing Procedure ER-AB-331-1001, "BWR RX Internals," Rev.1 OCGS Implementing Procedure ERR-AB-331, "BWR RX Internals Management Program Activities," Rev. 3 OCGS Implementing Procedure ER-AA-330-009, "ASME Section XI Repair/Replacement Program," Rev.3 PBD-AMP-B.1.08, "BWR Penetrations," Rev. 0, 11/22/2005
BWR Vessel Internals (B.1.9)	XI.M9, BWR Vessel Internals	PBD-AMP- B.1.9, ?BWR Vessel Internals," Rev. 0
Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (B.1.10)	XI.M13, Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel	PBD-AMP- B.1.10, ?Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel," Rev. 0, 12/15/2005
Flow-Accelerated Corrosion (B.1.11)	XI.M17, Flow-Accelerated Corrosion	PBD-AMP- B.1.11, ?Flow-Accelerated Corrosion," Rev. 0
Bolting Integrity (B.1.12)	XI.M18, Bolting Integrity	PBD-AMP- B.1.12, ?Bolting Integrity," Rev. 0
Open-Cycle Cooling Water System (B.1.13)	XI.M20, Open-Cycle Cooling Water System	PBD-AMP-B.1.13, ?Oyster Creek Program Basis Document Open Cycle Cooling Water System," Rev. 0, 12/7/2005 TR 140, ?Emergency Service Water and Service Water System Piping Plan," Rev. 2, May 4, 2005 ER-AA-340, ?GL 89-13 Program Implementing Procedure," Rev.2, undated SP-1302-12-261, ?Safety-related Specification for Pipe Integrity Inspection Program," Rev.7, 12/15/2004 & Rev. 8a, undated TDR-829, ?Inspection History of the OCNGS Pipe Integrity Program (Pipe Integrity Inspection Program)," Rev. 4, 12/15/2004 6007.4.007, ?Containment Spray and Emergency Service Water System 1 Pump Operability Test," Rev. 18, undated
Closed-Cycle Cooling Water System (B.1.14)	XI.M21, Closed-Cycle Cooling Water System	PBD-AMP-B.1.14, ?Oyster Creek Program Basis Document: Closed Cycle Cooling Water Systems," Rev. 0 12/19/05 WTC Project No. 1049, ?Closed Cycling Cooling Water Chemistry Assessment Oyster Creek Nuclear Generating Station," 09/06/2001

Applicant's Aging Management Program	**GALL Report Aging Management Program**	**LRA-AMP Basis Document and Other Documents Reviewed**
		EPRI 1007820, ?Closed Cycle Cooling Water Chemistry Guidelines," Revision 1, Final Report April 2004 CY-AA-120-400, ?Closed Cooling Water Chemistry Strategic Plan," Rev. 8 309.1.1, ?Turbine Building Closed Cooling Water Routine Evolutions" CY-AA120-110, ?Chemistry Limits and Frequencies," Rev. 0 642.4.001, ?RBCCW In-service Test," Rev. 25 636.4.003, ?Diesel Generator #1 Load Tests," Rev. 73 CAP 02000, ?1408 UT Measurements of RBCCW Piping," 10/10/2000
Boraflex Rack Management Program (B.1.15)	XI.M22, Boraflex Monitoring	PBD-AMP-B.1.15, ?OCGS Program Basis Document: Boraflex Rack Management Program," Rev. 0
Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.1.16)	XI.M23, Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	PBD-AMP-B.1.16, ?OCGS Program Basis Document: Inspection of Overhead heavy Load and Light Load (Related to Refueling) handling Systems," Rev. 0, undated OCGS CAP Report O2000-1446, 10/15/2000 OCGS CAP Report O2004-0601, 02/24/2004 OCGS CAP Report O2004-2877, 10/03/2004
Compressed Air Monitoring (B.1.17)	XI.M24, Compressed Air Monitoring	PBD-AMP-B.1.17, ?Oyster Creek Program Basis Document: Compressed Air Monitoring," Rev. 0, 11/28/2005 CAP-02004-0647, ?Failure of Both Sets of Instrument Air Dryers," 03/17/2004 ISA-S7.0.01-1996, ?Quality Standard for Instrument Air," 11/12/1996 SDBD-OC-852, ?Plant Compressed Air System Design Basis Document," Rev. 3 R0800446/PM 00811, ?Instrument Air System Dew Point and Particulate Status," 06/25/2001 R0800738, ?Instrument Air Leak Test, MSIV V 1-7 Status," 03/25/2001 Correspondence file no 88156, ?OCNGS Response to GL 88-14," 02/21/1992

Applicant's Aging Management Program	GALL Report Aging Management Program	LRA-AMP Basis Document and Other Documents Reviewed
		Correspondence No. C321-92-2072, ?OCNGS Status of Actions in Response to GL 88-14," March 9, 1992 Lesson Plan 2611, ?PBGD Service Instrument and Breathing Air, Course 828.0.0043," Rev. 8, 8/30/2004
BWR Reactor Water Cleanup System (B.1.18)	XI.M25, BWR Reactor Water Cleanup System	OCGS Document OC-2, ?IGSCC Inspection Program (GL 88-01 and BWRVIP-75)," Rev. 0, 07/31/2003 GPU Letter to NRC 1940-00-20096, ?Oyster Creek Request to Eliminate Inspections," April 13, 2000 PBD-AMP-B.1.18, ?OCGS Program Basis Document: BWR Reactor Water Cleanup System," Rev. 0, 11/17/2005
Fire Protection (B.1.19)	XI.M26, Fire Protection	PBD-AMP-B.1.19, ?Oyster Creek Program Basis Document: Fire Protection Rev. 0," 11/23/2005 CC-AA-211, ?Fire Protection Program," Rev. 1 645.6.017, ?Fire Barrier Penetration Surveillance," Rev. 10, 06/2004 101.2, ?Oyster Creek Site Fire Protection Program," Rev. 54 645.6.013, ?Fire Suppression System Halon Functional Test," Rev. 19, 06/2005 645.6.016, ?Fire Suppression Low Pressure CO2 System Functional Test," Rev. 8, 02/2003 645-6.028, ?Thermo-Lag and Mecatiss Envelope System Fire Barriers," Rev. 7, 11/17/2000 02000-390, ?Wall Penetration Seal Shrinkage," 03/20/2000 02000-1356, ?Damaged Block Wall in Electric Tray Room," 09/17/2002 02001-0601, ?Discrepancies During Fire Door Self Assessment Walkdown," 04/12/2001 02001-0247, ?Fire Damper Failures During SEB Fire Alarm and Halon Circuitry Surveillance Test (645.6.030)," 02/16/2001 LIB R0802114, ?Fire Door Evaluation Status," June 25, 2001 LIB R0802129, ?Fire Door Evaluation Status," June 25, 2001 LIB R0802166, ?Fire Door Evaluation Status," June 25, 2001
Fire Water System (B.1.20)	XI.M27, Fire Water System	PBD-AMP-B.1.20, ?Oyster Creek Program Basis Document: Fire Water System," Rev 0, 12/01/2005

Applicant's Aging Management Program	GALL Report Aging Management Program	LRA-AMP Basis Document and Other Documents Reviewed
		NFPA 25, ?Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems," 1998 Edition CAP 02002-0916, ?Leakage Noted During Fire Protection System Flush (645.6.007) CAP 02002-1019, ?Increased Cleaning Frequency of Micron Filters at Dilution Plant," Event date 07/12/2002 Program Health Report, ?Oyster Creek Fire Protection/Fire Safe Shutdown Program 4th Quarter," 2003 SP-1302-52-108, ?Specification for Inspection of Tanks," Rev. 3, 05/13/1992 101.2, ?Oyster Creek Site Fire Protection Program," Rev. 54 645.6.007, ?Fire Protection System Flush Rev. 15 645.6.003, ?Fire Hose Station, Hose House and Fire Hydrant Inspection," Rev. 18 R0804258 PM81101M, ?MIC Testing of Fire Protection Water Status," 29 June 2001 645.6.012, ?Fire Pump Functional Test," Rev. 29 645.6.011, ?Deluge and Sprinkler System Inspection," Rev. 11 CC-AA-211, ?Fire Protection Program," Rev.1
Aboveground Outdoor Tanks (B.1.21)	XI.M29, Aboveground Carbon Steel Tanks	PBD-AMP-B.1.21, ?OCGS Program Basis Document: Aboveground Outdoor Tanks," Rev. 0, 11/21/2005
Fuel Oil Chemistry (B.1.22)	XI.M30, Fuel Oil Chemistry	NUREG-1433, ?Standard Technical Specifications General Electric Plants, BWR/4," Vol. 1, Rev. 3.0, June 2004 NRC Regulatory Guide 1.137, ?Fuel Oil Systems for Standby Diesel Generators," Rev. 1, October 1979 ASTM Standard D 2276-00, ?Standard Test Method for particulate Contamination in Aviation fuel by Line Sampling," 2000 ASTM Standard D 2709-96, ?Standard Test method for Water and Sediment in Middle distillate Fuels by Centrifuge," 1996 ASTM Standard D 4057-95, ?Standard Practice for Manual Sampling of Petroleum and Petroleum Products," 2000

Applicant's Aging Management Program	**GALL Report Aging Management Program**	**LRA-AMP Basis Document and Other Documents Reviewed**
		PBD-AMP-B.1.22, ?OCGS Program Basis Document: Fuel Oil Chemistry," Rev. 0, 11/21/2005 OCGS Implementing Procedure CY-OC-120-1107, ?Fuel Oil Sample and Analysis Schedule," Rev. 0, undated OCGS Implementing Procedure CY-OC-130-7001, ?Water and Sediment," Rev. 0, undated OCGS Implementing Procedure 327.1, ?Fuel Oil Receipt and handling Procedure," Rev. 30, undated OCGS Implementing Procedure 828.7, ?Secondary Systems Analysis: Plant Oil," Rev. 22, undated OCGS Specification SP-1302-38-010, ?OCGS Specification for Oyster Creek Generating Station Diesel Fuel Oil No. 2," Rev. 8, 06/23/2004
Reactor Vessel Surveillance (B.1.23)	XI.M31, Reactor Vessel Surveillance	PBD-AMP-B.1.23, ?OCGS Program Basis Document: Reactor Vessel Surveillance," Rev. 0
One-Time Inspection (B.1.24)	XI.M32, One-Time Inspection	OCGS Report, ?Inspection Sample Basis, Oyster Creek License Renewal Project," August 16, 2005 PBD-AMP-B.1.24, ?OCGS Program Basis Document: One-Time Inspection," Rev. 0, undated EPRI Report 1000701, ?Interim Thermal Fatigue Management Guideline (MRP-24)," January 2001
Selective Leaching of Materials (B.1.25)	XI.M33, Selective Leaching of Materials	PBD-AMP- B.1.25, ?Selective Leaching of Materials," Rev. 0, 12/04/2005
Buried Piping Inspection (B.1.26)	XI.M34, Buried Piping and Tanks Inspection	PBD-AMP- B.1.26, ?Buried Piping Inspection," Rev. 0, 12/04/2005
ASME Section XI, Subsection IWE (B.1.27)	XI.S1, ASME Section XI, Subsection IWE	PBD-AMP- B.1.27, ?ASME Section XI, Subsection IWE," Rev. 0, 12/04/2005
ASME Section XI, Subsection IWF (B.1.28)	XI.S3, ASME Section XI, Subsection IWF	PBD-AMP- B.1.28, ?ASME Section XI Subsection IWF," Rev. 0, 12/04/2005 OCGS Focus Area Self Assessment Report April 26-29, 2004 CAP 02004-736 CAP 02001-1187 ASME Section XI, 1995 Edition, Subsection IWF

Applicant's Aging Management Program	GALL Report Aging Management Program	LRA-AMP Basis Document and Other Documents Reviewed
		2400-GMM-3900.52, ?Inspection and Torquing of Bolt Connections," Rev. 3 ER-AA-330, ?Conduct of In Service Inspection Activated," Rev. 4 ER-AA-330-003, ?In-service Inspection of Section XI Component Supports," Rev. 3 ER-AA-335-016, ?VT-3 Visual Examination of Component Supports and Attachments," Rev. 2 OC-1, ?OC ASME Section XI Program Plan Fourth Ten Year Inspection Interval," Rev. 1 09/30/04
10 CFR Part 50, Appendix J (B.1.29)	XI.S4, 10 CFR Part 50, Appendix J	PBD-AMP-B.1.29, ?10 CFR Part 50, Appendix J, Rev. 0, 12/01/2005 02000-1355;02002-1564, ?Plant Operating Experience" 02004-3442.;02005-1350 ?Plant Operating Experience" Oyster Creek FSAR (excerpt) Table 6.2-12, "Containment Isolation Valve/Mechanical Integrity," 28 pages ER-AA-380, ?Primary Containment Leakage Rak Testing Program," Rev. 3 ER-OC-380, ?Oyster Creek Primary Containment Leakage Rate Testing Program," Rev. 0
Masonry Wall Program (B.1.30)	XI.S5, Masonry Wall Program	PBD-AMP- B.1.30, ?Masonry Wall Program," Revision 0, 12/18/05 CAP-02003-0038, ?Issue Report-Various Deficiencies Identified by NRC" CAP-02002-0065, ?Issue Report- Crack in between Pour Wall and Concrete Block" ACI-201-1R-92, ?Guide for Making Condition Survey of Concrete in Service" ACI-530-92-ASCE 5-92, ?Building Code Requirements for Masonry Structure" TDR 830, ?Masonry Blockwall Walk Down Per IEB-8-11," Rev. 1, 09/18/88
Structures Monitoring Program (B.1.31)	XI.S6, Structures Monitoring Program	PBD-AMP-B.1.31, ?OCGS Program Basis Document: Structures Monitoring Program," Rev. 0

Applicant's Aging Management Program	GALL Report Aging Management Program	LRA-AMP Basis Document and Other Documents Reviewed
		125.6, ?Building Structure Monitoring Program," Rev. 4 2400-GMM-3900.52, ?Inspection and Torquing of Boltek Connections," Rev. 3 NUREG-1801 & ACI 349.38.02, ?Evaluation of Existing Nuclear Safety-related Concrete Structure," Rev. 1, June 17, 2002 10 CFR 50.65, ?Maintenance Rule" SP-1302-53-051, ?Specification for Periodic Monitoring of the Concrete Cracks in the Reactor Building Structure"
RG 1.127, Inspection of Water-Control Structures Associated With Nuclear Power Plant (B.1.32)	XI.S7, RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	PBD-AMP-B.1.32, ?OCGS Program Basis Document: RG 1.127, Inspection of Water-Control Structures Associated With Nuclear Power Plants," Rev. 0
Protective Coating Monitoring and Maintenance Program (B.1.33)	XI.S8, Protective Coating Monitoring and Maintenance Program	PBD-AMP-B.1.33, ?OCGS Program Basis Document: Protective Coating Monitoring and Maintenance Program," Rev. 0
Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.1.34)	XI.E1, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	PBD-AMP-B.1.34, ?Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualifications Requirements" NUERG/CR-5643, ?Insights Gained From Aging Research," U.S. Nuclear Regulatory Commission, March 1992 EPRI TR-109619, ?Guideline for the Management of Adverse Localized Equipment Environments," Electric Power Research Institute, Palo Alto, CA, June 1999 IEEE Std. P1205-2000, ?IEEE Guide for Assessing, Monitoring and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations" SAND96-0344, ?Aging Management Guideline for Commercial Nuclear Power Plants- Electrical Cable and Terminations,"prepared by Sandia National Laboratories for the US Department of Energy, September 1996 Oyster Creek Engineering Standard ES-027, ?Environmental Parameters- Oyster Creek NGS," Rev. 4, 06/13/2000 Oyster Creek Specification, SP-9000-41-005, ?Installation Specification for Cables and Raceways at Oyster Creek," Revision 5, 08/16/86

Applicant's Aging Management Program	**GALL Report Aging Management Program**	**LRA-AMP Basis Document and Other Documents Reviewed**
Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (B.1.35)	XI.E2, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	PBD-AMP-B.1.35, ?Electrical Cables and Connections Not subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits" Oyster Creek Procedure 2400-SMI-3623.03, ?IRM, SRM, LPRM Characterization Trending and Diagnostics" Oyster Creek Procedure 2400-SMI-3623.08, ?IRM Detector Current-Voltage (I.V.) Testing" Oyster Creek Routing Work Order R0802887 for implementing 2400-SMI-3623.03 Oyster Creek Surveillance Test 621.3.005, ?High Radiation Monitor- Reactor Building Isolation-Calibration" Oyster Creek Routing Work Order R0803575 for implementing ST 621.3.002 LS-AA-125, ?Corrective Action Program (CAP) Procedure," Revision 9 OC Procedure 2400-SMI-3623.08, ?IRM Detector Current-Voltage (I.V.) Testing" OC Procedure 2400-SMI-3623.09, ?Calibration and Operation of the LPRM Diagnostic System," Revision 11 OC Procedure 621.3.002, ?Air Ejector Off Gas Radiation Monitor Check Source Functional Test," Revision 25 OC Procedure 621.3.005, ?High Radiation Monitor (Reactor Building Isolation) Calibration," Revision 46 330592.35.02, 2400-SMI-3623.08, ?Procedure Revision (I.V. testing for IRMs) for OC License Renewal" 330592.35.09, ST21302A Work Order revision request to implement 621.3.002 for OC License Renewal Oyster Creek Technical Specifications, Table 4.1.1
Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.1.36)	XI.E3, Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	PBD-AMP-B.1.36, ?Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements" EPRI TR-109619, ?Guideline for the Management of Adverse Localized Equipment Environments," June 1999 IEEE Std 400-2001, ?IEEE Guide for Field Testing and Evaluation of the Insulation of Shielded Power Cable Systems," January 2002

Applicant's Aging Management Program	GALL Report Aging Management Program	LRA-AMP Basis Document and Other Documents Reviewed
		Engineering Evaluation 0164-97, ?Oyster Creek Medium Voltage Cable Test Program," May 15, 1997 Oyster Creek 2.4 kV and 4.16kV cable test matrix prepared in support of October 2004. NRC AMP audit; Subsequently revised and submitted in the AmerGen response to RAI 2.5.1.19-1 for the Forked River Combustion Turbine, October 12, 2005; Subsequently revised to reconcile differences between the draft revision of NUREG 1801, January 2005 and the issued Revision 1 to NUREG 1801, September 2005. LS-AA-125, ?Corrective Action Program (CAP) Procedure," Revision 9 OC Procedure 2400-SME-378.05, ?Power Factor Testing of 5kV Cables," Revision 2 (Used as part of current cable testing program.) OC Procedure 2400-SME-3780.06, ?Dielectric Testing for 2.3 kV and 5kV Cables and Equipment," Revision 8 (Used as part of current cable testing program) Example of completed WO for DTE Testing, C2008036 EPRI TR-1003057, ?License Renewal Electrical Handbook," December 2001 EPRI TR-1003664, ?Medium-Voltage Cables in Nuclear Plant Applications- State of Industry and Conditioning Monitoring," October 2003 AmerGen response to RAI 2.5.1.19-1, October 12, 2005 Oyster Creek Engineering Evaluation 0164-97, ?Oyster Creek Medium Voltage Cable Test Program," May 15, 1997 "White Paper" Appendix E, on Assessment of Underground Cable Failures, submitted to the state of New Jersey, Bureau of Nuclear Engineering, 7/25/05
Periodic Monitoring of Combustion Turbine Power Plant Electrical (B.1.37)	NA	Information Notice 89-64, ?Electrical Bus Bal Failures" Information Notice 2000-14, "Non-Vital Bus Fault Leads to Fire and Loss of Off-Site Power" LS-AA-125, ?Corrective Action Program (CAP) Procedure," Revision 9 IEEE Std 1205-2000, ?IEEE Guide for Assessing, Monitoring and Mitigating Aging Affects on Class 1E Equipment Used in Nuclear Power Generating Stations," 03/30/2000

Applicant's Aging Management Program	**GALL Report Aging Management Program**	**LRA-AMP Basis Document and Other Documents Reviewed**
		RAI Response to NRCRAI 2.5.1.19-1, 10/12/05 AR A2078783, corrective maintenance EPRI TR-109619, ?Guidelines for the Management of Adverse Localized Equipment Environments," June 1999
Periodic Testing of Containment Spray Nozzles (B.2.1)	Oyster Creek plant-specific program	Assigned to DE
Lubricating Oil Monitoring Activities (B.2.2)	Oyster Creek plant-specific program	Assigned to DE
Generator Stator Water Chemistry Activities (B.2.3)	Oyster Creek plant-specific program	Assigned to DE
Periodic Inspection of Ventilation Systems (B.2.4)	Oyster Creek plant-specific program	Assigned to DE
Periodic Inspection Program (B.2.5)	Oyster Creek plant-specific program	Assigned to DE
Periodic Monitoring of Combustion Turbine Power Plant (B.2.7)	Oyster Creek plant-specific program	AMP deleted by applicant.
Metal Fatigue of Reactor Coolant Pressure Boundary (B.3.1)	X.M1, Metal Fatigue of Reactor Coolant Pressure Boundary	PBD-AMP-B.3.01, ?Metal Fatigue of Reactor Coolant Pressure Boundary," Rev. 0, 12/07/2005 Ref. 3.14.1, "Cycle based Fatigue development for RPV, Torus & Isolation Condenser Locations" Ref. 314.14, "Cycle counting & cycle based fatigue report for the transient & fatigue monitoring system for the Oyster Creek Generating Station" Ref. 314.15, ?Transfer Function & System Logic report for Transient & Fatigue Monitoring System for the OC Feedwater Nozzles" Ref. 314.16, ?Report on System Review & Recommendations for Transient & Fatigue Monitoring System at the Oyster Creek Generating Station" Ref. 314.17, "Oyster Creek Station-Unit 1 Operational Records Review for License Renewal" Calculation Package, ?Cycle Based Fatigue Development for

Applicant's Aging Management Program	GALL Report Aging Management Program	LRA-AMP Basis Document and Other Documents Reviewed
		RPV, Torus, and Isolation Condenser Locations," Rev. 0 AmerGen AR No. A2114740 Eval 5, "Transient Cycle Counting Long Table for OCNGS through 7/1/2005," SI file # OC-0512-212 3.14.2 "Fatigue Evaluation for Feedwater Piping" 3.14.7 "40-Year & 60 year Cycle Projections & Fatigue Pro Historical Base Lining" 3.14.8 "Environmental Fatigue Calculations for RPV Locations" 3.14.18 "Fatigue Pro Historical Baselining"
Environmental Qualification (EQ) Program (B.3.2)	X.E1, Environmental Qualification (EQ) of Electrical Components	PBD-AMP-B.3.02, ?Environmental Qualification Program"
Oyster Creek Station Blackout System Forked River Combustion Turbine AMPs		
Bolting Integrity – FRCT (B.1.12A)	XI.M18 Bolting Integrity	PBD-AMP-B.1.12A, ?FRCT Program Basis Document: Bolting Integrity – FRCT," Rev. 0
Closed Cycle Cooling Water System – FRCT (B.1.14A)	XI.M21 Closed-Cycle Cooling Water System	PBD-AMP-B.1.14A, ?FRCT Program Basis Document: Closed-Cycle Cooling Water System – FRCT," Rev. 0
Aboveground Outdoor Tanks – FRCT (B.1.21A)	XI.M29, Aboveground Outdoor Tanks	PBD-AMP-B.1.21A, ?FRCT Program Basis Document: Aboveground Outdoor Tanks – FRCT," Rev. 0
Fuel Oil Chemistry – FRCT (B.1.22A)	XI.M30, Fuel Oil chemistry	PBD-AMP-B.1.22A, ?FRCT Program Basis Document: Fuel Oil Chemistry – FRCT," Rev. 0, 11/04/2005 TAQ Engineering Inc., Tank Certification Report, unnumbered, October 30, 2000
One-Time Inspection – FRCT (B.1.24A)	XI.M32, One-Time Inspection	PBD-AMP-B.1.24A, ?OCGS Program Basis Document: One-Time Inspection – FRCT," Rev. 0, 11/04/2006 OCGS Letter to NRC 2130-05-20228, ?Supplemental Response to NRC Request for Additional Information (RAI 2.5.1.19-1), dated September 28, 2005, Related to Oyster Creek Generating Station License Renewal Application (TAC No. MC7624)," November 11, 2005
Selective Leaching of Materials – FRCT (B.1.25A)	XI.M33, Selective Leaching of Materials	PBD-AMP-B.1.25A, ?FRCT Program Basis Document: Selective Leaching of Materials – FRCT," Rev. 0

Applicant's Aging Management Program	GALL Report Aging Management Program	LRA-AMP Basis Document and Other Documents Reviewed
Buried Piping Inspection – FRCT (B.1.26A)	XI.M34, Buried Piping Inspection	PBD-AMP-B.1.26A, ?FRCT Program Basis Document: Buried Piping Inspection – FRCT," Rev. 0
Buried Piping Inspection-Met Tower (B.1.26B)	XI.M34, Buried Piping Inspection	PBD-AMP-B.1.26B, ?Met Tower Program Basis Document: Buried Piping Inspection-Met Tower," Rev. 0
Periodic Monitoring of Combustion Turbine Power Plant-Electrical (B.1.37)	NA	PBD-AMP-B.1.37, ?FRCT Program Basis Document: Periodic Monitoring of Combustion Turbine Power Plant-Electrical," Rev. 0
Inspection of Internal Surfaces in Miscellaneous Piping and ducting Components – FRCT (B.1.38)	XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and ducting Components	PBD-AMP-B.1.38, ?FRCT Program Basis Document: Inspection of Internal Surfaces in Miscellaneous Piping and ducting Components – FRCT," Rev. 0
Lubricating Oil Analysis – FRCT (B.1.39)	XI.M39, Lubricating Oil Analysis	PBD-AMP-B.1.39, ?FRCT Program Basis Document: Lubricating Oil Analysis – FRCT," Rev. 0
Periodic Inspection – FRCT (B.2.5A)	NA	PBD-AMP-B.2.5A, ?FRCT Program Basis Document: Periodic Inspection – FRCT," Rev. 0

Applicant's AMR Sections and Systems for OCGS	OCGS LRA-AMR Basis Document and Other Documents Reviewed
3.1 Reactor Vessel, Internals, and Reactor Coolant Systems	OC-AMR-2.3.1.5, ?Reactor Head Cooling System," Rev. 0, 12/13/05 OC-AMR-2.3.1.6, ?Reactor Internals," Rev. 0, 12/713/05 BWR-VIP -139, ?Steam Dryer and Inspection & Flaw Evaluation Guidelines," 2/2005 OC-AMR-2.3.1.7, ?Reactor Pressure Vessel," Rev. 0, 12/7/05 OC-AMR-2.3.1.8, ?Reactor Recirculation System," Rev. 0, 12/16/05
3.2 Engineered Safety Features Systems	OC-AMR-2.3.1.3, ?Isolation Condenser System," Rev. 0, 12/13/05 OC-AMR-2.3.1.4, ?Nuclear Boiler Instrumentation," Rev. 0, 12/13/05 OC-AMR-2.3.2.2, ?Containment Spray System," Rev. 1, 12/13/05

Applicant's AMR Sections and Systems for OCGS	OCGS LRA-AMR Basis Document and Other Documents Reviewed
	OC-AMR-2.3.2.3, ?Core Spray System," Rev. 0, 12/28/05 OC-AMR-2.3.2.4, ?Standby Gas Treatment System," Rev. 0, 12/12/05
3.3 Auxiliary Systems	OC-AMR-2.3.3.1, ?C Battery Room Heating & Ventilation," Rev. 0, 12/12/05 OC-AMR-2.3.3.2, ?4160 Switchgear Room Ventilation," Rev. O, 12/16/05 OC-AMR-2.3.3.3, ?480 Switcgear Room Ventilation," Rev. 0, 12/28/05 OC-AMR-2.3.3.4, ?Battery and Mg Set Room Ventilation," Rev. 0 1/17/06 OC-AMR-2.3.3.5, ?Chlorination System," Rev. 0, 12/5/05 OC-AMR-2.3.3.6, ?Circulation Water System," Rev. 0, 1/9/06 OC-AMR-2.3.3.7, ?Containment Inerting System," Rev. 0, 12/9/05 OC-AMR-2.3.3.8, ?Containment Vacuum Breakers," Rev. 0 12/27/05 OC-AMR-2.3.3.9, ?Control Rod Drive System," Rev. 0, 12/14/05 OC-AMR-2.3.3.10, ?Control Room HVAC," Rev. 0 12/13/05 OC-AMR-2.3.3.11, ?Cranes and Hoists," Rev. 0, 12/28/05 OC-AMR-2.3.3.12, ?Drywell Floor and Equipment Drains," Rev. 0, 1/19/06 OC-AMR-2.3.3.13, ?Emergency Diesel Generator and Auxiliary System," Rev. 0, 12/19/05 OC-AMR-2.3.3.14, ?Emergency Service Water System," Rev. 0, 12/21/05 OC-AMR-2.3.3.15, ?Fire Protection System," Rev. 0, ½5/06 OC-AMR-2.3.3.16, ?Fuel Storage and Handling Equipment," Rev. 0, 12/23/05 OC-AMR-2.3.3.17, ?Hardened Vent System," Rev. 0, 12/16/05 OC-AMR-2.3.3.18, ?Heating & Process Steam," Rev. 0, 1/13/06

Applicant's AMR Sections and Systems for OCGS	OCGS LRA-AMR Basis Document and Other Documents Reviewed
	OC-AMR-2.3.3.19, ?Hydrogen & Monitoring System," Rev. 0, 12/19/05 OC-AMR-2.3.3.20, ?Instrument (Control) Air System," Rev.0, 12/7/05 OC-AMR-2.3.3.21, ?Main Fuel Oil Storage & Transfer System," Rev. 0, 12/5/05 OC-AMR-2.3.3.22, ?Miscellaneous Floor and Equipment Drain System," Rev. 0, 1/6/06 OC-AMR-2.3.3.23, ?Nitrogen Supply System," Rev. 0, 12/5/05 OC-AMR-2.3.3.24, ?Noble Monitoring System," Rev. 0, 12/21/05 OC-AMR-2.3.3.25, ?Post-accident Sampling System," Rev. 0, 12/21/05 OC-AMR-2.3.3.26, ?Process Sampling System," Rev. 0, 12/21/05 OC-AMR-2.3.3.27, ?Radiation Monitoring System," Rev. 0, 12/14/05 OC-AMR-2.3.3.28, ?Radwaste Area Heating and Ventilation System," Rev. 0, 12/16/05 OC-AMR-2.3.3.29, ?Reactor Building Closed Cooling Water System," Rev. 1, 2/10/06 OC-AMR-0M-2.3.3.30, ?Reactor Building Floor and Equipment Drains," Rev. 0, 1/11/06 OC-AMR-2.3.3.31, ?Reactor Building Ventilation System," Rev. 0, 1/3/06 OC-AMR-2.3.3.32, ?Reactor Water Cleanup System," Rev. 0, 12/7/05 OC-AMR-2.3.3.32, ?Roof Drains and Overboard Discharge," Rev. 0, 1/4/06 OC-AMR-2.3.3.34, ?Sanitary Waste System," Rev. 0, 1/4/06 OC-AMR-2.3.3.35, ?Service Water System," Rev. 0, 1/13/06 OC-AMR-2.3.3.36, ?Shutdown Cooling System," Rev. 0, 1/3/06 OC-AMR-2.3.3.37, ?Spent Fuel Pool Cooling System," Rev. 0, 1/6/06

Applicant's AMR Sections and Systems for OCGS	OCGS LRA-AMR Basis Document and Other Documents Reviewed
	OC-AMR-2.3.3.3.38, ?Standby Liquid Control System," Rev. 0, 1/13/06 OC-AMR-2.3.3.39, ?Traveling In-core Probe System," Rev. 0, 1/4/06 OC-AMR-2.3.3.40, ?Turbine Building Closed Cooling Water System," Rev. 0, 12/14/05 OC-AMR-2.3.3.41, ?Water Treatment & Distr. System," Rev. 0, 1/5/06 Holtec Report HI-2043279, Project No. 1405, ?Summary Report of the Examination of Oyster Creek Nuclear Station Boral Surveillance." Holtec Report HI-2033000, Project No. 1256, ?Examination of Oyster Creek Nuclear Station Boral Surveillance."
3.4 Steam and Power Conversion Systems	OC-AMR 2.3.4.1, ?Condensate System," REV. 0 1/12/06 OC-AMR-2.3.4.2, ?Condensate Transfer System," Rev. 0, 1/12/06 OC-AMR-2.3.4.3, ?Feedwater System," Rev. 0, 12/16/05 OC-AMR-2.3.4.4, ?Main Condenser," Rev. 0, 12/21/05 OC-AMR-2.3.4.5, ?Main Generator and Auxiliary System," Rev. 0, 12/19/05 OC-AMR-2.3.4.6, ?Main Steam System," Rev. 0, 1/18/06 OC-AMR-2.3.4.7, ?Main Turbine and Auxiliary System," Rev. 0, 12/5/05
3.5 Primary Containment, Structures, Component Supports, and Piping and Component Insulation	OC-AMR-2.5.1, ?Station Blackout System," Rev. 0, 1/4/06 OC-AMR-2.5.1.15, ?Radio Communications Systems," Rev. 0, 12/28/05 OC-AMR-S-2.4.2, ?Primary Containment," Rev. 0 1/13/06 OC-AMR-S-2.4.2, ?Structures Other than Containment," Rev. 1, 2/10/06 OC-AMR-S-2.4.3, ?Component Supports Commodity Group," Rev. 1, 2/10/06 NUREG-0822, "Integrated Plant Safety Assessment, Systematic Evaluation Program", Oyster Creek Nuclear Generating Station Final Report Dated January 1983. Letter, J. Zwolinsky (NRC) to P. Fiedler (GPUN) with a Safety Evaluation 4.12 (SEP Topic III-7.B) NRC Information Request Form of NUREG-0822, Design Codes, Design Criteria and

Applicant's AMR Sections and Systems for OCGS	OCGS LRA-AMR Basis Document and Other Documents Reviewed
	Load Combinations, Dated Oct. 29, 1986. Letter from Alexander W. Dromerick, Jr. (NRC) to J. Barton (GPU), "Oyster Creek Nuclear Generating station – Evaluation of Effects of High Temperature on drywell Shield Wall and Biological Shield Wall, SEP Topic III-7.B "Design Codes, Design Criteria, Load Combinations, and Reactor Cavity Criteria" (TAC No. M76879) dated May 11, 1994. Letter from R.W. Keaten to U.S. NRC, "Oyster Creek Nuclear Generating Station (OCNGS) Docket 50-219 SEP Topic III-7B, drywell Shield Wall Integrity", dated April 19, 1994 Letter, R. Keaton (GPUN) to NRC, Response to Request for Additional Information on Drywell Temperature (SEP Topic III-7.B), Dated November 19, 1993. Holtec Report HI-981983, "Licensing Report for Storage Capacity Expansion of Oyster Creek Spent Fuel Pool", Revision 4, dated June 15, 1999 MPR-953, "GPU Nuclear Corporation, Oyster Creek Nuclear Generating Station Torus Shell Thickness Margin", MPR Associates INC, October 1986. Calculation No. C-1302-187-E310-038, "Oyster Creek Torus Corrosion Allowable Pit Depth", October 2002
3.6 Electrical Components	OC-AMR-2.5.1, ?Electrical Commodities," Rev. 0, 1/3/06 PLI-02, Oyster Creek License Renewal Project Level Instruction 2 "Scoping of Systems, Structures, and Commodities," Rev. 4, 9/8/05 PLI-03, Oyster Creek License Renewal Project Level Instruction 3 "Scoping of Systems and Structures," Rev. 2, 9/8/05 PLI-08, Oyster Creek License Renewal Project Level Instruction 8 "Program Basis Documents," Rev. 7, ½4/06 PP-15 "Standard Materials, Environments, and Aging Effects, "Oyster Creek License Renewal Project, Rev. 5, 1/31/06 EPRI 1003057, ?License Renewal Electrical Handbook," Final, December 2001 EPRI-TR-109619, ?Guideline for the Management of Adverse Localized Equipment Environments," Final, June 1999

ATTACHMENT 6: LIST OF COMMITMENTS

The following table lists all commitments identified by the applicant in Appendix A, Table A.5 of the OCGS LRA that were reviewed by the project team. This list reflects revisions to the commitment list in Table A.5 of the OCGS LRA provided by the applicant in the following license renewal submittals:

- AmerGen Letter 2130-05-20214, ?Response to NRC Request for Additional Information (RAI 2.5.1.19-1), dated September 28, 2005, Related to Oyster Creek Generating Station License Renewal Application (TAC No. MC7624)," dated October 12, 2005.

- AmerGen Letter 2130-05-20228, ?Supplemental Response to NRC Request for Additional Information (RAI 2.5.1.19-1), dated September 28, 2005, Related to Oyster Creek Generating Station License Renewal Application (TAC No. MC7624), dated November 11, 2005.

- AmerGen Letter 2130-05-20239, ?Response to NRC Request for Additional Information dated November 9, 2005, Related to Oyster Creek Generating Station License Renewal Application (TAC No. MC7624)," dated December 9, 2005.

This list also reflects new audit commitments made by the applicant during this audit, and documented in the following license renewal submittals:

- AmerGen Letter 2130-06-20293, ?Reconciliation of Oyster Creek Generating Station License Renewal Application with September 2005 Revision 1, NUREG-1800 and NUREG-1801 (TAC No. MC7624)," dated March 30, 2006.

- AmerGen Letter 2130-06-20284, ?Commitments Associated with Containment (Drywell and Torus) Condition Monitoring Related to AmerGen Application for Renewed Operating License – Oyster Creek Generating Station (TAC No. MC7624)," dated April 4, 2006.

- AmerGen Letter 2130-06-20316,"Responses to Action Items Associated with Oyster Creek Generating Station License Renewal Audits (TAC No. MC7624)," dated April 17, 2006.

- AmerGen Letter 2130-06-20328, ?Supplemental Commitments Associated with AmerGen Application for Renewed Operating License – Oyster Creek Generating Station (TAC No. MC7624)," Dated May 1, 2006.

The commitment numbers in the table are those assigned by the applicant in the OCGS LRA, with the exception of new audit commitments made by the applicant as a result of this audit and review, which are numbered based on the section number of the audit report in which they are discussed.

Commitment No.	Audit and Review Report Section	Description
1) ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	3.0.3.2.1	Existing program is credited. For the isolation condensers this program also includes enhancement activities identified in NUREG-1801, lines IV.C1-5 and IV.C1-6. These enhancement activities consist of: 1. Temperature and radioactivity monitoring of the shell-side (cooling) water, which will be implemented prior to the period of extended operation. 2. Eddy current testing of the tubes, with inspection (VT or UT) of the tubesheet and channel head, which will be performed during the first ten years of the extended period of operation.
2) Water Chemistry	3.0.3.2.2	Existing program is credited.
3) Reactor Head Closure Studs	3.0.3.2.3	Existing program is credited.
4) BWR Vessel ID Attachment Welds	3.0.3.2.4	Existing program is credited.
5) BWR Feedwater Nozzle	3.0.3.2.5	Existing program is credited. The Oyster Creek Feedwater Nozzle aging management program will be enhanced to implement the recommendations of the BWR Owners Group Licensing Topical Report General Electric (GE) NE-523-A71-0594.
6) BWR Control Rod Drive Return Line Nozzle	3.0.3.2.6	Existing program is credited.
7) BWR Stress Corrosion Cracking	3.0.3.2.7	Existing program is credited.
3.0.3.2.7-1	3.0.3.2.7	The applicant committed to revise AMP B.1.7 in the OCGS LRA to include the enhancement identified in the program basis document, PBD-AMP-B.1.07, which stated that for those components within the scope of the BWR stress corrosion cracking aging management program, all new and replacement SS materials will be low-carbon grades of SS with carbon content limited to 0.035 wt. % maximum and ferrite content limited to 7.5% minimum.
8) BWR Penetrations	3.0.3.2.8	Existing program is credited.
9) BWR Vessel Internals	3.0.3.2.9	Existing program is credited. The program will be enhanced to include: 1. Inspection of the steam dryer in accordance with BWRVIP-139. 2. Inspection of the top guide as recommended in NUREG-1801. 3. Rolling of the CRD stub tubes as a permanent repair, once the NRC approves the ASME code case. If the ASME code

Commitment No.	Audit and Review Report Section	Description
		case is not approved, the program will be changed to use a permanent repair acceptable to the NRC.
10) Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)	3.0.3.1.1	Program is new. The program will include a component specific evaluation of the loss of fracture toughness in accordance with the criteria specified in NUREG-1801, XI.M13. For those components where loss of fracture toughness may affect the intended function of the component, a supplemental inspection will be performed. This inspection will ensure the integrity of the CASS components exposed to the high temperature and neutron fluence present in the reactor environment.
11) Flow- Accelerated Corrosion	3.0.3.1.2	Existing program is credited.
12) Bolting Integrity	3.0.3.2.10	Existing program is credited.
3.0.3.2.10-1.	3.0.3.2.10	The applicant committed to revise the bolting integrity program (B.1.12) in the OCGS LRA to include the enhancement identified in the program basis document, which stated that the site procedure will be enhanced to include reference to EPRI TR-104213, ?Bolted Joint Maintenance & Application Guide," December 1995.
13) Open-Cycle Cooling Water System	3.0.3.2.11	Existing program is credited. The program will be enhanced as follows. Volumetric inspections, for piping that has been replaced, will be included at a minimum of 4 aboveground locations every 4 years. Inspection of heat exchangers will specify examination for loss of material due to general, pitting, crevice, galvanic and MIC in the RBCCW, TBCCW and Containment Spray preventative maintenance tasks.
14) Closed-Cycle Cooling Water System	3.0.3.2.12	Existing program is credited.
15) Boraflex Monitoring	3.0.3.2.13	Existing program is credited.
16) Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	3.0.3.2.14	Existing program is credited. The scope of the program will be increased to include additional hoists that have been identified as a potential Seismic II/I concern and are in scope for 10CFR54.4(a)(2). The program will also be enhanced to include inspections for rail wear, and loss of material due to corrosion, of cranes and hoists structural components, including the bridge, the trolley, bolting, lifting devices, and the rail system.
17) Compressed Air Monitoring	3.0.3.1.3	Existing program is credited.
18) BWR Reactor Water Cleanup System	3.0.3.2.15	Existing program is credited. Based on GL 89-10 containment isolation valve upgrades/ enhancements, an effective Hydrogen Water Chemistry Program, and the complete lack of cracking found during any of the RWCU piping weld inspections performed under GL 88-01, all inspection requirements for the portion of the RWCU System outboard of the second

Commitment No.	Audit and Review Report Section	Description
		containment isolation valves have been eliminated.
19) Fire Protection	3.0.3.2.16	Existing program is credited. The program will be enhanced to include: 1. Specific fuel supply inspection criteria for fire pumps during tests. 2. Inspection of external surfaces of the halon and carbon dioxide fire suppression systems. 3. Additional inspection criteria for degradation of fire barrier walls, ceilings, and floors.
3.0.3.2.16-1	3.0.3.2.16	The applicant committed to revise AMP B.1.19 in the OCGS LRA to add the enhancement to the OCGS fire protection program, related to periodic visual inspections of fire door surface integrity and clearance checks, as described in the program basis document, PBD-AMP-B.1.19, to the OCGS LRA.
20) Fire Water System	3.0.3.2.17	Existing program is credited. The program will be enhanced to include: 1. Sprinkler head testing in accordance with NFPA 25, ?Inspection, Testing and Maintenance of Water-Based Fire Protection Systems." Samples will be submitted to a testing laboratory prior to being in service 50 years. This testing will be repeated at intervals not exceeding 10 years. 2. Water sampling for the presence of MIC at an interval not to exceed 5 years. 3. Periodic non-intrusive wall thickness measurements of selected portions of the fire water system at an interval not to exceed every 10 years. 4. Visual inspection of the redundant fire water storage tank heater during tank internal inspections.
21) Aboveground Outdoor Tanks	3.0.3.2.18	Program is new. The program will manage the corrosion of outdoor carbon steel and aluminum tanks. The program credits the application of paint, sealant, and coatings as a corrosion preventive measure and performs periodic visual inspections to monitor degradation of the paint, sealant, and coatings and any resulting metal degradation.
3.0.3.2.18-1	3.0.3.2.18	The applicant committed to revise the aboveground outdoor tanks program (B.1.21) in the OCGS LRA to include the exception identified in the program basis document, which stated that the specified frequency by the Oyster Creek program is every 5 years in place of system walkdowns each outage.

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22) Fuel Oil Chemistry	3.0.3.2.19	Existing program is credited. The program will be enhanced to include: 1. Routine analysis for particulate contamination using modified ASTM D 2276-00 Method A on fuel oil samples from the Emergency Diesel Generator Fuel Storage Tank, the Fire Pond Diesel Fuel Tanks, and the Main Fuel Oil Tank. 2. Analysis for particulate contamination using modified ASTM D 2276-00 Method A on new fuel oil. 3. Analysis for water and sediment using ASTM D 2709-96 for Fire Pond Diesel Fuel Tank bottom samples. 4. Analysis for bacteria to verify the effectiveness of biocide addition in the Emergency Diesel Generator Fuel Storage Tank, the Fire Pond Diesel Fuel Tanks, and the Main Fuel Oil Tank. 5. Periodic draining, cleaning, and inspection of the Fire Pond Diesel Fuel Tanks and the Main Fuel Oil Tank. Inspection activities will include the use of ultrasonic techniques for determining tank bottom thicknesses should there be any evidence of corrosion or pitting.
3.0.3.2.19-1	3.0.3.2.19	The applicant committed to revise OCGS AMP B.1.22, fuel oil chemistry, in the OCGS LRA to include a one-time internal inspection of the EDG day tanks to confirm the absence of aging effects. Visual inspection will be performed and further inspections will be performed to quantify the degradation, should there be any evidence of corrosion or pitting observed during the visual inspection.
3.0.3.2.19-2	3.0.3.2.19	The applicant committed to revise AMP B.1.22 in the OCGS LRA to include the exception identified in the reconciliation document, which stated that Oyster Creek has not adopted the Standard Technical Specifications, however, the Oyster Creek fuel oil specifications and procedures invoke similar requirements for fuel oil purity and fuel oil testing.
23) Reactor Vessel Surveillance	Assigned to NRR/DE	Existing program is credited. The program will be enhanced to implement BWRVIP-116 ?Integrated Surveillance Program (ISP) Implementation for License Renewal," if approved by the NRC. If BWRVIP-116 is not approved, Exelon will provide a plant-specific surveillance plan for the license renewal period in accordance with 10 CFR Part 50, Appendices G and H prior to entering the period of extended operation.
24) One-Time Inspection	3.0.3.1.4	Program is new. The One-Time Inspection program will provide reasonable assurance that an aging effect is not occurring, or that the aging effect is occurring slowly enough to not affect the component or structure intended function during the period of extended operation, and therefore will not require additional aging management. This program will be used for the

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		following: 1. To confirm crack initiation and growth due to SCC, IGSCC, or thermal and mechanical loading is not occurring in Class 1 piping less than four-inch nominal pipe size (NPS) exposed to reactor coolant. 2. To confirm the effectiveness of the Water Chemistry Program to manage the loss of material and crack initiation and growth aging effects. 3. To confirm the effectiveness of the Closed Cycle Cooling Water System program to manage the loss of material aging effect. 4. To confirm the effectiveness of the Fuel Oil Chemistry program and Lubricating Oil Monitoring Activities program to manage the loss of material aging effect. 5. To confirm loss of material in stainless steel piping, piping components, and piping elements is insignificant in an intermittent condensation (internal) environment. 6. To confirm loss of material in steel piping, piping components, and piping elements is insignificant in an indoor air (internal) environment. 7. To confirm loss of material is insignificant for non-safety-related (NSR) piping, piping components, and piping elements of vents and drains, floor and equipment drains, and other systems and components that could contain a fluid, and, are in scope for 10CFR54.4(a)(2) for spatial interaction. The scope of the program consists of only those systems not covered by other aging management activities.
3.0.3.1.4-1	3.0.3.1.4	The one-time inspection aging management program does not verify the effectiveness of the selective leaching of materials aging management program. The applicant committed to correct line item 43 in Table 3.3.1 to delete reference to using the one-time inspection to verify the effectiveness of the selective leaching of materials program.
3.0.3.1.4-2	3.0.3.1.4	The applicant committed to revise AMP B.1.24 in the OCGS LRA to include the exception identified in the reconciliation document, which states that the new Oyster Creek one-time inspection aging management program will include the one-time inspection of Class 1 piping less than or equal to NPS 4.
3.0.3.1.4-3	3.0.3.1.4	The one-time inspection program will also include destructive or non-destructive examination of one socket welded connection using techniques proven by past industry experience to be effective for the identification of cracking in small bore socket

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		welds. Should an inspection opportunity not occur (e.g., socket weld failure or socket weld replacement), a susceptible small-bore socket weld will be examined either destructively or non-destructively prior to entering the period of extended operation.
3.0.3.1.4-4	3.0.3.1.4	The applicant committed to revise AMP B.1.24 in the OCGS LRA to include the exception identified in the reconciliation document, which states that the 1995 ASME Section XI B&PV Code, including 1996 addenda, is currently used at Oyster Creek.
3.0.3.1.4-5	3.0.3.1.4	The applicant committed to revise AMP B.1.24 in the OCGS LRA to include the exception identified in the reconciliation document, which states that EPRI Report 1000701 is not applicable at Oyster Creek.
25) Selective Leaching of Materials	3.0.3.1.5	Program is new. The Selective Leaching of Materials program will consist of inspections of a representative selection of components of the different susceptible materials to determine if loss of material due to selective leaching is occurring. Visual inspections will be consistent with ASME Section XI VT-1 visual inspection requirements and supplemented by hardness tests and other examinations of the selected set of components. If selective leaching is found, the condition will be evaluated to determine the need to expand inspections.
26) Buried Piping Inspection	3.0.3.2.21	Existing program is credited. The program will be enhanced to include: 1. Inspection of buried piping within ten years of entering the period of extended operation, unless an opportunistic inspection occurs within this ten-year period. 2. The buried portions of the fire protection system and the piping located inside the vault.
3.0.3.2.21-1	3.0.3.2.21	The applicant committed to replace the previously un-replaced buried safety-related ESW piping prior to the period of extended operation.
27) ASME Section XI, Subsection IWE	3.0.3.2.22	Existing program is credited.
3.0.3.2.22-1	3.0.3.2.22	Consistent with current practice, a strippable coating will be applied to the reactor cavity liner to prevent water intrusion into the gap between the drywell shield wall and the drywell shell during periods when the reactor cavity is flooded. This commitment applies to refueling outages prior to and during the period of extended operation.
3.0.3.2.22-2	3.0.3.2.22	The reactor cavity seal leakage trough drains and the drywell sand bed region drains will be monitored for water leakage periodically.

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3.0.3.2.22-3	3.0.3.2.22	AmerGen will conduct UT thickness measurements in the upper regions of the drywell shell every other refueling outage at the same locations as are currently measured. This will be performed every other refueling outage prior to and during the period of extended operation.
3.0.3.2.22-4	3.0.3.2.22	Prior to the period of extended operation, AmerGen will perform additional visual inspections of the epoxy coating that was applied to the exterior surface of the drywell shell in the sand bed region, such that the coated surfaces in all 10 drywell bays will have been inspected at least once. In addition, the inservice inspection (ISI) program will be enhanced to require inspection of 100% of the epoxy coating every 10 years during the period of extended operation. These inspections will be performed in accordance with ASME Section XI, Subsection IWE. Performance of the inspections will be staggered such that at least three bays will be examined every other refueling outage. This commitment applies prior to the period of extended operation, and every ten years during the period of extended operation.
3.0.3.2.22-5	3.0.3.2.22	Ultrasonic Testing (UT) thickness measurements of the drywell shell in the sand bed region will be performed on a frequency of every 10 years. The initial inspection will occur prior to the period of extended operation. The UT measurements will be taken from the inside of the drywell at the same locations where UT measurements were performed in 1996. The inspection results will be compared to previous results. Statistically significant deviations from the 1992, 1994, and 1996 UT results will result in corrective actions that include the following: a) perform additional UT measurements to confirm the readings; b) notify NRC within 48 hours of confirmation of the identified condition; c) conduct visual inspection of the external surface in the sand bed region in areas where any unexpected corrosion may be detected; d) perform engineering evaluation to assess the extent of condition and to determine if additional inspections are required to assure drywell integrity; and e) perform operability determination and justification for operation until next inspection. These actions will be completed prior to restart from the associated outage.
3.0.3.2.22-6	3.0.3.2.22	During the next UT inspections to be performed on the drywell sand bed region (reference AmerGen 4/4/06 letter to NRC), an attempt will be made to locate and evaluated some of the locally thinned areas identified in the 1992 inspection from the exterior of the drywell. This testing will be performed using the latest UT methodology with existing shell paint in place. The UT thickness measurements for these locally thinned areas may be taken from either inside the drywell or outside the drywell (sand bed region) to limit radiation dose to as low as reasonably achievable (ALARA).

Commitment No.	Audit and Review Report Section	Description
3.0.3.2.22-7	3.0.3.2.22	As noted in AmerGen's 4/4/06 letter to NRC, AmerGen will perform torus coating inspections in accordance with ASME Section XI, Subsection IWE every other refueling outage prior to and during the period of extended operation. This new commitment clarifies that the scope of each of these inspections will include the wetted area of all 20 torus bays. Should the current torus coating system be replaced, the inspection frequency and scope will be re-evaluated. Inspection scope will, as a minimum, meet the requirements of ASME Section XI, Subsection IWE.
3.0.3.2.22-8	3.0.3.2.22	AmerGen will develop refined acceptance criteria and thresholds for entering torus coating defects and unacceptable pit depths into the corrective action process for further evaluation. These improvements will be incorporated into the inspection implementing documents prior to the next performance of these inspections, which is also prior to the period of extended operation.
28) ASME Section XI, Subsection IWF	3.0.3.2.23	Existing program is credited. The scope of the program will be enhanced to include additional MC supports, and require inspection of the underwater supports for loss of material due to corrosion and loss of mechanical function and loss of preload on bolting by inspecting for missing, detached, or loosened bolts.
29) 10 CFR Part 50, Appendix J	3.0.3.1.6	Existing program is credited.
30) Masonry Wall Program	3.0.3.1.7	Existing program is credited. The Masonry Wall Program is part of the Structures Monitoring Program.
31) Structures Monitoring Program	3.0.3.2.24	Existing program is credited. The program includes elements of the Masonry Wall Program and the RG 1.127, Inspection of Water-Control Structures Associated With Nuclear Power Plants aging management program. The Structures Monitoring Program will be enhanced to include: 1. Buildings, structural components and commodities that are not in scope of maintenance rule but have been determined to be in the scope of license renewal. These include miscellaneous platforms, flood and secondary containment doors, penetration seals, sump liners, structural seals, and anchors and embedment. 2. Component supports, other than those in scope of ASME XI, Subsection IWF. 3. Inspection of Oyster Creek external surfaces of mechanical components that are not covered by other programs, HVAC duct, damper housings, and HVAC closure bolting. Inspection and acceptance criteria of the external surfaces will be the same as those specified for structural steel components and structural bolting.

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		4. The visual inspection of insulated surfaces will require the removal of insulation. Removal of insulation will be on a sampling basis that bounds insulation material type, susceptibility of insulated piping or component material to potential degradations that could result from being in contact with insulation, and system operating temperature. 5. Inspection of electrical panels and racks, junction boxes, instrument racks and panels, cable trays, offsite power structural components and their foundations, and anchorage. 6. Periodic sampling, testing, and analysis of ground water to confirm that the environment remains non-aggressive for buried reinforced concrete. 7. Periodic inspection of components submerged in salt water (Intake Structure and Canal, Dilution structure) and in the water of the fire pond dam, including trash racks at the Intake Structure and Canal. 8. Inspection of penetration seals, structural seals, and other elastomers for change in material properties. 9. Inspection of vibration isolators, associated with component supports other than those covered by ASME XI, Subsection IWF, for reduction or loss of isolation function. 10. The current inspection criteria will be revised to add loss of material, due to corrosion for steel components, and change in material properties, due to leaching of calcium hydroxide and aggressive chemical attack for reinforced concrete. Wooden piles and sheeting will be inspected for loss of material and change in material properties. 11. Periodic inspection of the Fire Pond Dam for loss of material and loss of form. 12. Inspection of Station Blackout System Structures, structural components, and phase bus enclosure assemblies. 13. Inspection of Forked River Combustion Turbine power plant external surface of mechanical components that are not covered by other programs, HVAC duct, damper housings, and HVAC closure bolting. Inspection and acceptance criteria of the external surfaces will be the same as those specified for structural steel components and structural bolting. 14. The program will be enhanced to Include Inspection of Meteorological Tower Structures. Inspection and acceptance criteria will be the same as those specified for other structures In the scope of the program.

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		15. The program will be enhanced to include Inspection of exterior surfaces of piping and piping components associated with the Radio Communications system, located at the meteorological tower site, for loss of material due to corrosion. inspection and acceptance criteria will be the same as those specified for other external surfaces of mechanical components.
3.0.3.2.24-1	3.0.3.2.24	The applicant committed to add the exception identified in its reconciliation document for the structures monitoring program, which states that the program takes exception to the inspection frequency of at least once per refueling cycle specified in NUREG-1801, XI.M36.
3.0.3.2.24-2	3.0.3.2.24	The September 2005 Revision 1 GALL program specifies monitoring for leakage. The Oyster Creek structures monitoring program will be enhanced to require visual inspection of external surfaces of mechanical steel components that are not covered by other programs for leakage from or onto external surfaces, worn, flaking, or oxide-coated surfaces, corrosion stains on thermal insulation, and protective coating degradation (cracking and flaking). This is a new enhancement based on the reconciliation of this aging management program from the January 2005 draft GALL to the approved September 2005 Revision 1 GALL.
3.0.3.2.24-3	3.0.3.2.24	The applicant committed to revise the structures monitoring program (AMP B.1.31) in the OCGS LRA to include an inspection frequency for submerged portions of water control structures that is consistent with the new commitment identified in PBD-AMP-B.1.32 for the submerged water control structures program
32) RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	3.0.3.2.25	Existing program is credited. The program is part of the Structures Monitoring Program. The RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program will be enhanced to include: 1. Monitoring of submerged structural components and trash racks. 2. Periodic inspection of components submerged in salt water (Intake Structure and Canal, Dilution structure) and in the water of the fire pond dam. 3. Periodic inspection of the Fire Pond Dam for loss of material and loss of form. 4. Inspection of steel components for loss of material, due to corrosion. 5. Inspection of wooden piles and sheeting for loss of material and change in material properties.

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		6. Parameters monitored will be enhanced to include change in material properties, due to leaching of calcium hydroxide, and aggressive chemical attack.
3.0.3.2.25-1	3.0.3.2.25	The applicant committed to revise the LRA AMP B.1.32 to add the exception to the inspection frequency specified in NUREG-1801 XI.S7 stated in program basis document PBD-AMP-B.1.32. The applicant has committed to a baseline inspection prior to entering the period of extended period of operation, a second inspection 6 years after the baseline inspection, and a third inspection 8 years after the second inspection, and has committed to evaluate the identified degradations to determine if more frequent inspections are warranted.
33) Protective Coating Monitoring and Maintenance Program	3.0.3.1.8	Existing program is credited. The Oyster Creek Protective Coating Monitoring and Maintenance Program provides for aging management of Service Level I coatings inside the primary containment and Service Level II coatings for the external drywell shell in the area of the sand bed region.
3.0.3.1.8-1	3.0.3.1.8	The applicant committed revise LRA Tables 3.5.2.1.1 and 3.5.1 to delete the protective coating monitoring and maintenance program (B.1.33) from line items to manage loss of material for access hatch covers, drywell penetration sleeves, and personnel airlock/equipment hatch exposed to a containment atmosphere (internal) environment, and line items to manage corrosion for the vent line, and vent header exposed to an indoor air (external) environment.
3.0.3.1.8-2	3.0.3.1.8	The coating inside the torus will be visually inspected in accordance with ASME Section XI, Subsection IWE, per the protective coatings program. This commitment will be performed every other refueling outage prior to and during the period of extended operation.
34) Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	3.0.3.1.9	Program is new. The program will be used to manage aging of non-EQ cables and connections during the period of extended operation. A representative sample of accessible cables and connections located in adverse localized environments will be visually inspected at least once every 10 years for indications of accelerated insulation aging.
35) Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	3.0.3.2.26	Existing program is credited. The program will be enhanced to include: 1. A review of the Reactor Building High Radiation Monitoring and Air Ejector Offgas Radiation Monitoring system calibration results for cable aging degradation before the period of extended operation and every 10 years thereafter. 2. A review of the LPRM/APRM and IRM system cable testing results for cable aging degradation before the period of extended operation and every 10 years thereafter.

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36) Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	3.0.3.1.10	Program is new. The program manages the aging of inaccessible medium-voltage cables that feed equipment performing license renewal intended functions. These cables may at times be exposed to moisture and are subjected to system voltage for more than 25% of the time. Manholes, conduits and sumps associated with these cables will be inspected for water collection every 2 years and drained as required. In addition, the cable circuits will be tested using a proven test for detecting deterioration of the insulation system due to wetting, such as power factor, partial discharge, or polarization index, as described in EPRI TR-103834-P1-2, or other testing that is state-of-the-art at the time the test is performed. The cables will be tested at least once every 10 years. Inclusion of the 13.8kV system circuits in this program reflects the scope expansion of the Station Blackout System electrical commodities.
3.0.3.1.10-1	3.0.3.10	The applicant committed to revise AMP B.1.36 in the OCGS LRA to clarify that the applicant does not use polarization index testing as the lone condition monitoring test for medium-voltage cable circuits.
3.0.3.1.10-2	3.0.3.10	The applicant committed to include both 13.8 and 34.5kV cables in its existing cable test program that currently only includes 2.4 and 4.16kV cables. This is a new enhancement based on the reconciliation of this aging management program from the January 2005 draft GALL to the approved September 2005 Revision 1 GALL.
3.0.3.1.10-3	3.0.3.10	The applicant committed to revise Appendix A Table A.05 commitment #36, and OCGS LRA Appendices A.1.36 and B.1.36, to state that cable test/monitoring frequency will be at least once every 10 years, that it will be adjusted based on test/monitoring results, and that the test results will be trended.
37) Periodic Testing of Containment Spray Nozzles	Assigned to NRR/DE	Existing plant specific program is credited. Carbon steel piping upstream of the drywell and torus spray nozzles is subject to possible general corrosion. The periodic flow tests of drywell and torus spray nozzles address a concern that rust from the possible general corrosion may plug the spray nozzles. These periodic tests verify that the drywell and torus spray nozzles are free from plugging that could result from corrosion product buildup from upstream sources.
38) Lubricating Oil Monitoring Activities	3.0.3.3.2	Existing plant specific program is credited. The program manages loss of material, cracking, and fouling in lubricating oil heat exchangers, systems, and components in the scope of license renewal by monitoring physical and chemical properties in lubricating oil. Sampling, testing, and monitoring verify lubricating oil properties. Oil analysis permits identification of specific wear mechanisms, contamination, and oil degradation within operating machinery, and components of systems in scope for license renewal. The program will be enhanced to add surveillance for verification of flow through the Fire

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		Protection System diesel driven pump gearbox lubricating oil cooler.
39) Generator Stator Water Chemistry Activities	Assigned to NRR/DE	Existing plant specific program is credited. The program manages loss of material aging effects by monitoring and controlling water chemistry. Generator stator water chemistry control maintains high purity water in accordance with General Electric and EPRI guidelines for stator cooling water systems.
40) Periodic Inspection of Ventilation Systems	Assigned to NRR/DE	Existing plant specific program is credited. The program includes internal and external surface inspections of ventilation system components for indications of loss of material, such as rust, corrosion and pitting. Heat transfer surfaces are inspected for fouling. Flexible connection and door seal elastomer materials are inspected for detrimental changes in material properties, as evidenced by cracking, perforations in the material or leakage. The program will be enhanced to include duct exposed to soil, instrument piping and valves, restricting orifices and flow elements, and thermowells. The activities will also be enhanced to include inspection guidance for detection of the applicable aging effects.
41) Periodic Inspection Program	3.0.3.3.5	Plant specific program is new. The program includes systems in the scope of license renewal that require periodic monitoring of aging effects, and are not covered by other existing periodic monitoring programs. Activities consist of a periodic inspection of selected systems and components to verify integrity and confirm the absence of identified aging effects. The inspections are condition monitoring examinations intended to assure that existing environmental conditions are not causing material degradation that could result in a loss of system intended functions.
42) Wooden Utility Pole Program	Assigned to NRR/DE	Plant specific program is new. The program is used to manage loss of material and change of material properties for wooden utility poles in or near the Oyster Creek Substation that provide structural support for the conductors connecting the Offsite Power System and the 480/208/120V Utility (JCP&L) Non-Vital Power System to the Oyster Creek plant. The program consists of inspection on a 10-year interval by a qualified inspector. The wooden poles are inspected for loss of material due to ant, insect, and moisture damage and for change in material properties due to moisture damage.
43) Periodic Monitoring of Combustion Turbine Power Plant	A7.3.0.3.3.1	A new plant specific program is credited. The program will be used in conjunction with the existing Structures Monitoring Program and the new Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program to manage aging effects for the electrical commodities that support FRCT operation. The program consists of visual inspections of accessible electrical cables and connections exposed in enclosures, pits, manholes and pipe trench; visual inspection for water collection in manholes, pits and trenches, located on the FRCT site, for

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		inaccessible medium voltage cables; and visual inspection of accessible phase bus and connections and phase bus insulators/supports. The new program will be performed on a 2-year interval for manhole, pit and trench inspections, on a 5-year interval for phase bus inspections, and on a 10-year interval for cable and connection inspections.
44) Metal Fatigue of Reactor Coolant Pressure Boundary	3.0.3.2.27	Existing program is credited. The program will be enhanced to use the EPRI-licensed FatiguePro cycle counting and fatigue usage factor tracking computer program. The computer program provides for calculation of stress cycles and fatigue usage factors from operating cycles, automated counting of fatigue stress cycles and automated calculation and tracking of fatigue cumulative usage factors. The program will also be enhanced to provide for calculating and tracking of the cumulative usage factors for bounding locations for the reactor pressure vessel, Class I piping, the torus, torus vents, torus attached piping and penetrations, and the isolation condenser.
3.0.3.2.27-1	3.0.3.2.27	The applicant committed to certification by a Professional Engineer of the reactor vessel design specification and design reports prepared for the fatigue activities associated with the LRA. This will be performed by July 31, 2006**.**
45) Environmental Qualification (EQ) Program	3.0.3.1.11	Existing program is credited. EQ components that cannot be qualified for 60-years will be replaced before the end of their qualified life.
46) New P-T Curves	Assigned to NRR/DE	Revised pressure-temperature (P-T) limits for a 60-year licensed operating life have been prepared and will be submitted to the NRC for approval.
47) Circumferential Weld Exam Relief	Assigned to NRR/DE	Apply for extension Reactor Vessel Circumferential Weld Examination Relief for 60-year operation
48) Axial weld Exam Relief	Assigned to NRR/DE	Apply for extension Reactor Vessel Axial Weld Examination Relief for 60-year operation
49) Measure Drywell wall thickness	Assigned to NRR/DE	Drywell wall thickness will be monitored to ensure minimum wall thickness is maintained. The ASME Section XI, Subsection IWE aging management program, will manage the aging effects.
50) Fluence Methodology	Assigned to NRR/DE	The NRC has issued a SER for RAMA approving RAMA for reactor vessel fluence calculations. Oyster Creek will comply with the applicable requirements of the SER.
51) Bolting Integrity – FRCT	A7.3.0.3.2.1	The Bolting Integrity – FRCT aging management program is a new program that provides for condition monitoring of bolts and bolted joints within the scope of license renewal at the Forked River Combustion Turbine power plant. This program is based on the General Electric recommendations for proper bolting material selection, lubrication, preload application, installation and maintenance associated with the combustion turbine units and auxiliary systems. The program also includes periodic

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		walkdown inspections for bolting degradation or bolted joint leakage at a frequency of at least once every four years. The program manages the loss of material and loss of preload aging effects. This new program will be implemented prior to entering the period of extended operation.
52) Closed-Cycle Cooling Water System – FRCT	A7.3.0.3.2.2	The Closed-Cycle Cooling Water System – FRCT aging management program is a new program that manages aging of piping, piping components, piping elements and heat exchangers that are included in the scope of license renewal for loss of material and cracking, and are exposed to a closed cooling water environment at the Forked River Combustion Turbine power plant. The Closed-Cycle Cooling Water System – FRCT aging management program relies on preventive measures to minimize corrosion by maintaining water chemistry control parameters and by performing system monitoring and maintenance inspection activities to confirm that the aging effects are adequately managed. Chemistry control, performance monitoring and inspection activities are based on industry-recognized guidelines of EPRI TR-107396, "Closed Cooling Water Chemistry Guidelines," for closed-cycle cooling water systems. Chemical control parameters will be monitored by annual water chemistry sampling. System operational monitoring activities will be performed at a frequency of at least once every six months. This new program will be implemented prior to entering the period of extended operation.
53) Aboveground Steel Tanks – FRCT	A7.3.0.3.2.3	The Aboveground Steel Tanks – FRCT aging management program is a new program that will manage corrosion of aboveground outdoor steel tanks. Paint coating is a corrosion preventive measure, and periodic visual inspections will monitor degradation of the paint coating and any resulting metal degradation of tank external surfaces. The aboveground tanks external surfaces will be visually inspected for coating degradation by walkdown at least once every two years. The Main Fuel Oil tank bottom is in contact with concrete and soil, and is inaccessible for visual inspection. Therefore, the program includes periodic Nondestructive wall-thickness examinations of the Main Fuel Oil tank bottom to verify that significant corrosion is not occurring. This program, including the initial tank external paint inspections, will be implemented prior to the period of extended operation. The recommended UT inspection of the Main Fuel Oil tank bottom was performed in October 2000, so it is not necessary to perform this inspection again prior to entering the period of extended operation. Based on the results of the October 2000 inspections, and subsequent repairs to the tank floor, the tank was certified to be suitable for the storage of number 2 fuel oil for a period of time not to exceed 20 years from October 2000, before the next internal inspection would be necessary. Therefore, additional UT inspections will be performed prior to October 2020.

Commitment No.	Audit and Review Report Section	Description
54) Fuel Oil Chemistry – FRCT	A7.3.0.3.2.4	The Fuel Oil Chemistry – FRCT aging management program is a new program that provides assurance that contaminants are maintained at acceptable levels in new and stored fuel oil for systems and components within the scope of Licensing Renewal. The Fuel Oil Storage Tank will be maintained by monitoring and controlling fuel oil contaminants in accordance with the guidelines of the American Society for Testing Materials (ASTM). Fuel oil sampling activities will be in accordance with ASTM D 4057 for multilevel and tank bottom sampling. Fuel oil will be periodically sampled and analyzed for particulate contamination in accordance with modified ASTM Standard D 2276 Method A or ASTM Standard D 6217, and, for the presence of water and sediment in accordance with ASTM Standard D 2709 or ASTM Standard D 1796. The Fuel Oil Storage Tank will be periodically drained of accumulated water and sediment and will be periodically drained, cleaned, and internally inspected. These activities effectively manage the effects of aging by providing reasonable assurance that potentially harmful contaminants are maintained at low concentrations. This new program will be implemented prior to entering the period of extended operation. The internal inspection of the Main Fuel Oil tank was performed in October 2000, so it is not necessary to perform this inspection again prior to entering the period of extended operation. Based on the results of the October 2000 inspections and repairs, the tank was certified to be suitable for the storage of number 2 fuel oil for a period of time not to exceed 20 years from October 2000, before the next internal inspection would be necessary. Therefore, additional internal inspections of the tank floor are not necessary prior to entering the period of extended operation and will be performed prior to October 2020.
55) One Time Inspection – FRCT	A7.3.0.3.2.5	The One-Time Inspection – FRCT program will provide measures to verify that an aging management program is not needed, confirms the effectiveness of existing activities, or determines that degradation is occurring which will require evaluation and corrective action. The program will be implemented prior to the period of extended operation. Inspection methods will include visual examination or volumetric examinations. Should aging effects be detected, the program will initiate actions to characterize the nature and extent of the aging effect and determines what subsequent monitoring is needed to ensure intended functions are maintained during the period of extended operation.
56) Selective Leaching of Materials – FRCT	A7.3.0.3.2.6	The Selective Leaching of Materials – FRCT aging management program is a new program that will consist of inspections of components constructed of susceptible materials to determine if loss of material due to selective leaching is occurring. For the FRCT power plant, these are limited to copper alloy materials exposed to a closed cooling water environment. One-time inspections will be consist of visual inspections supplemented by hardness tests. If selective

Commitment No.	Audit and Review Report Section	Description
		leaching is found, the condition will be evaluated to determine the ability of the component to perform its intended function until the end of the period of extended operation and for the need to expand inspections. This new program will be implemented in the time period after January 2018 and prior to January 2028.
57) Buried Piping Inspection – FRCT	A7.3.0.3.2.7	The Buried Piping Inspection – FRCT aging management program is a new program that manages the external surface aging effects of loss of material for carbon steel piping and piping system components in a soil (external) environment. The program activities consist of preventive and condition-monitoring measures to manage the loss of material due to external corrosion for piping and piping system components in the scope of license renewal that are in a soil (external) environment. The program scope includes buried portions of glycol cooling water piping located at the Forked River Combustion Turbine station. External inspections of buried components will occur opportunistically when they are excavated during maintenance. Within 10 years prior to entering the period of extended operation, inspection of buried piping will be performed unless an opportunistic inspection occurs within this ten-year period. Upon entering the period of extended operation, inspection of buried piping will again be performed within the next ten years, unless an opportunistic inspection occurs during this ten-year period. This program will be implemented prior to entering the period of extended operation.
58) Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components – FRCT	A7.3.0.3.2.10	The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components – FRCT aging management program is a new program that consists of visual inspections of the internal surfaces of steel piping, valve bodies, ductwork, filter housings, fan housings, damper housings, mufflers and heat exchanger shells in the scope of license renewal at the Forked River Combustion Turbine power plant that are not covered by other aging management programs. Internal inspections will be performed during scheduled maintenance activities when the surfaces are made accessible for visual inspection. The program includes visual inspections to assure that existing environmental conditions are not causing material degradation that could result in a loss of component intended functions. These inspections will be performed during the major combustion turbine inspection outages and will be performed on a frequency of at least once every 10 years. The initial inspections associated with this program will be performed at the next major inspection outage for each unit. Based on an inspection frequency of 10 years, the next inspection for CT Unit 1 will be performed by May 2014, and the next inspection for CT Unit 2 will be performed by November 2015.
59) Lubricating Oil Analysis Program –	A7.3.0.3.2.11	The Lubricating Oil Analysis Program – FRCT is a new program that includes measures to verify the oil environment in

Commitment No.	Audit and Review Report Section	Description
FRCT		mechanical equipment is maintained to the required quality. The Lubricating Oil Analysis Program – FRCT maintains oil systems contaminants (primarily water and particulates) within acceptable limits, thereby preserving an environment that is not conducive to loss of material, cracking, or reduction in heat transfer. Lubricating oil testing activities include sampling and analysis of lubricating oil for detrimental contaminants. The presence of water or particulates may also be indicative of inleakage and corrosion product buildup. This program is augmented by the One Time Inspection – FRCT (B.1.24A) program, to verify the effectiveness of the Lubricating Oil Analysis Program – FRCT. The new program will be implemented prior to the period of extended operation. The new program will be implemented prior to the period of extended operation.
60) Periodic Inspection Program – FRCT	A7.3.0.3.3.2	The Periodic Inspection Program – FRCT is a new program that will consist of periodic inspections of selected components to verify the integrity of the system and confirm the absence of identified aging effects. Inspections will be scheduled to coincide with major combustion turbine maintenance inspections, when the subject components are made accessible. These inspections will be performed on a frequency not to exceed once every 10 years. The purpose of the inspection is to determine if a specified aging effect is occurring. If the aging effect is occurring, an evaluation will be performed to determine the effect it will have on the ability of affected components to perform their intended functions for the period of extended operation, and appropriate corrective action is taken. Inspection methods may include visual examination, surface or volumetric examinations. When inspection results fail to meet established acceptance criteria, an evaluation will be conducted to identify actions or measures necessary to provide reasonable assurance that the component intended function is maintained during the period of extended operation. The initial inspections associated with this program will be performed at the next major inspection outage for each unit. Based on an inspection frequency of 10 years, the next inspection for CT Unit 1 will be performed by May 2014, and the next inspection for CT Unit 2 will be performed by November 2015.
61) Buried Piping and Tank Inspection – Met Tower Repeater Engine Fuel Supply	A7.3.0.3.2.12	The Buried Piping and Tank Inspection – Met Tower Repeater Engine Fuel Supply aging management program Is a new program that manages the external surface aging effects of loss of material for copper and carbon steel piping, and carbon steel tanks in a soil (external) environment. The program activities consist of preventive and condition-monitoring measures to manage the loss of material due to external corrosion for piping and piping system components in the scope of license renewal that are in a soil (external) environment. The program scope includes buried portions of the Met Tower based radio communications system repeater

Commitment No.	Audit and Review Report Section	Description
		backup engine generator fuel (propane) supply piping and the associated buried fuel supply tank, located at the Forked River Meteorological Tower. External inspections of buried components will occur opportunistically when they are excavated during maintenance. Within 10 years prior to entering the period of extended operation, inspection of buried piping will be performed unless an opportunistic inspection occurs within this ten-year period. Upon entering the period of extended operation, inspection of buried piping will again be performed within the next ten years, unless an opportunistic inspection occurs during this ten-year period. This program will be Implemented prior to entering the period of extended operation.
3.1.2.1.6-1	3.1.2.1.6	The applicant committed to revise LRA AMP B.1.9 to clarify its position related to the use of roll/expansion techniques for the repair of leaking CRD stub tubes which will result in no leakage of the CRD of the stub tubes during the extended period of operation.
3.1.2.1.12-1	3.1.2.1.12	The applicant committed to revising the OCGS LRA, Section 3.1, to address loss of material due to pitting and crevice corrosion in stainless steel and nickel alloy reactor vessel internal components. The BWR vessel internals AMP will be used to manage this aging effect.
3.1.2.2.1-1	3.1.2.2.1	The applicant committed to revise the AMR line items in LRA Table 3.1.2.1.4 for the reactor internals, and Table 3.1.2.1.5 for the reactor pressure vessel to delete the reference to TLAA for components where a TLAA does not exist. Further, the appropriate aging management program will be identified with an "E" industry standard note and a plant specific note stating: "There is no fatigue analysis for this component. The aging effect of cumulative fatigue is managed by the BWR Vessel Internals aging management program." Similarly for the feedwater nozzle and CRD return line nozzle thermal sleeves, the note will read: "There is no fatigue analysis for this component. The aging effect of cumulative fatigue is managed by the BWR Feedwater Nozzle (or BWR CRD Return Line Nozzle, as applicable) aging management program."
3.1.2.2.2-1	3.1.2.2.2	The applicant committed to performing a one-time UT inspection of the "B" Isolation Condenser shell for pitting corrosion, prior to the period of extended operation
3.1.2.2.2-2	3.1.2.2.2	The applicant committed to revise the OCGS LRA Section 3.1 to address loss of material due to pitting and crevice corrosion for stainless steel, nickel alloy, and steel with stainless steel or nickel alloy cladding flanges, nozzles, penetrations, pressure housings, safe ends, and vessel shells, heads and welds exposed to reactor coolant. The aging effect will be managed through the use of the water chemistry and one-time inspection programs. The selection of susceptible locations for one-time

Commitment No.	Audit and Review Report Section	Description
		inspections will be based on severity of conditions, time of service, and lowest design margin.
3.2.2.1.6-1	3.2.2.1.6	The applicant committed to revise the further evaluation in Section 3.2.2.2.8.2 of the OCGS LRA to state that Oyster Creek engineered safety features systems have no steel piping, piping components, or piping elements (internal surfaces) exposed to condensation, treated water (in the form of condensation wetting the internal surface), or air-indoor uncontrolled environments.
3.2.2.2.3-1	3.2.2.2.3	The applicant committed to revise OCGS LRA Table 3.2.1, line item 3.2.1-34 related to stainless steel piping, piping components, and piping elements exposed to lubricating oil in the engineered safety features systems to state that this material/environment combination is not applicable to Oyster Creek.
3.2.2.2.4-1	3.2.2.2.4	The applicant committed to revise OCGS LRA Table 3.1.2.1.1 for the isolation condenser system to include two new line items invoking one-time inspection to supplement the Water Chemistry Program for reduction of heat transfer due to fouling for the internal and external surfaces of the isolation condenser heat exchanger tubes. These are new additions based on the reconciliation of the Oyster Creek LRA between the January 2005 draft GALL and the approved September 2005 Revision 1 GALL.
3.3.2.1.1-1	3.3.2.1.1	The applicant committed to revise Table 3.3.2.1.18 in the OCGS LRA to include the water chemistry aging management program to address loss of material due to pitting and crevice corrosion for components constructed of copper and copper alloy in the heating and process steam system that are exposed to auxiliary steam and boiler treated water.
3.3.2.1.1-2.	3.3.2.1.1	The applicant committed to revise Table 3.3.2.1.41 in the OCGS LRA to address aging management of loss of material due to pitting and crevice corrosion for valve bodies constructed of brass and bronze exposed to treated water on the internal surface by adding the following AMR line items: • Valve Body – leakage boundary – brass – treated water (internal) – loss of material – water chemistry (B.1.2) – VII.E4-8 (AP-64) 3.3.1-38 • Valve Body – leakage boundary – brass – treated water (internal) – loss of material – one-time inspection (B.1.24) – VII.E4-8 (AP-64) 3.3.1-38 • Valve Body – leakage boundary – bronze – treated water (internal) – loss of material – water chemistry (B.1.2) – VII.E4-8 (AP-64) 3.3.1-38 • Valve Body – leakage boundary – bronze – treated water

Commitment No.	Audit and Review Report Section	Description
		(internal) – loss of material – one-time inspection (B.1.24) – VII.E4-8 (AP-64) 3.3.1-38
3.3.2.1.12-1	3.3.2.1.12	The applicant committed to revise Table 3.3.2.1.13 in the OCGS LRA for the emergency diesel generator and auxiliary system to address the aging effect for reduction of heat transfer due to fouling for the brass lube oil cooler and radiator tubes exposed to a closed cooling water environment by crediting the OCGS closed-cycle cooling water program (AMP B.1.14).
3.5.2.2.1-1	3.5.2.2.1	A visual examination of the drywell shell in the drywell floor inspection access trenches will be performed to assure that the drywell steel remains intact. If degradation is identified, the drywell shell condition will be evaluated and corrective actions taken, as necessary. These surfaces will either be inspected as part of the scope of the ASME Section XI, Subsection IWE inspection program, or they will be restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas. The applicant committed to perform a one-time visual inspection and UT measurements of the embedded drywell shell prior to entering the period of extended operation.
3.5.2.2.1-2	3.5.2.2.1	In addition to AmerGen's previous commitment to perform one-time visual examinations of the drywell shell in the areas exposed by the trenches in the bottom of the drywell (reference AmerGen 4/4/06 letter to NRC), one-time UT measurements will be taken to confirm the adequacy of the shell thickness in these areas, providing further confidence that the drywell remains capable of performing its intended function. This commitment will be performed prior to entering the period of extended operation.
A7.3.0.3.2.11-1	A7.3.0.3.2.11	The applicant committed to revise the lubricating oil analysis program – FRCT in LRA B.1.39 to include measurement of flash point.

ATTACHMENT 7
FORKED RIVER COMBUSTION TURBINES, RADIO COMMUNICATION SYSTEMS, AND METEOROLOGICAL TOWER LICENSE RENEWAL AUDIT AND REVIEW

In response to NRC Request for Additional Information (RAI) 2.5.1.19-1 and RAI 2.5.1.15-1 related to the Oyster Creek Generating Station (OCGS) license renewal application, the applicant provided submittals on October 12, 2005, November 11, 2005, and December 9, 2005, that address aging management of components and systems in the scope of license renewal for the OCGS station blackout system (SBO) system Forked River combustion turbines (FRCTs), Radio Communication systems, and Meteorological Tower. In the RAIs, the NRC expressed the need for additional information to evaluate the long-lived passive components of the FRCTs, and any aging management programs (AMPs) and aging management reviews (AMRs) related to those components. As a result, the applicant revised its approach to aging management for the OCGS SBO combustion turbine power plant Radio Communication Systems, and Meteorological Tower. Specifically, the applicant has taken a more detailed approach to scoping, screening, aging management reviews and aging management programs. The FRCTs are owned, operated, and maintained by First Energy and provide peak loading to the grid. Consistent with OCGS commitments, and as reviewed and approved by the NRC, the FRCTs provide a standby source of alternate ac power for the OCGS station in the event of an SBO.

As a result of the applicant's new approach to aging management of the FRCTs, 11 new AMPs have been added to the OCGS LRA, and two existing OCGS AMPs have been revised to incorporate the results of the more detailed AMRs. In addition, the previously submitted AMP B.2.7, ?Periodic Monitoring of the Combustion Turbine Power Plant," identified in the LRA has been deleted. The applicant has revised AMP B.1.31, ?Structures Monitoring Program," for OCGS structures to include structures, structural components and phase bus enclosure assemblies at the FRCT. The applicant has revised AMP B.1.36, ?Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualifications," to include inaccessible medium-voltage cables associated with the SBO system. The project team's audit and review activities of AMPs B.1.31 and B.1.36 are provided in Section 3.03 of this OCGS audit and review report.

The applicant added AMP B.1.37, ?Periodic Monitoring of Combustion Turbine Power Plant – Electrical," to address the remaining SBO system electrical commodities for which aging management is required. In addition, 10 new AMPs have been added to manage the effects of aging of mechanical components at the FRCT power plant. These new AMPs are as follows:

- B.1.12A: Bolting Integrity – FRCT
- B.1.14A: Closed-Cycle Cooling Water System – FRCT
- B.1.21A: Aboveground Steel Tanks – FRCT
- B.1.22A: Fuel Oil Chemistry – FRCT
- B.1.24A: One-Time Inspection – FRCT
- B.1.25A: Selective Leaching of Materials – FRCT
- B.1.26A: Buried Piping Inspection – FRCT

- B.1.26B: Buried Piping and Tank Inspection – Met Tower Repeater Engine Fuel Supply
- B.1.38: Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components – FRCT
- B.1.39: Lubricating Oil Analysis Program – FRCT
- B.2.5A: Periodic Inspection Program – FRCT

This Attachment to the OCGS audit and review report provides the results of the project team's audit and review activities related to the AMRs and AMPs for the OCGS FRCT power plant.

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Attachment 7 Tables

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A7.1 Introduction and General Information

A7.1.1 Introduction

By letter dated July 22, 2005 (Agencywide Documents Access and Management System [ADAMS] ADAMS Accession Number ML0520800480), AmerGen Energy Company, LLC, (AmerGen, the applicant) submitted to the U.S. Nuclear Regulatory Commission (NRC) its application for renewal of Facility Operating License No. DPR-16 for Oyster Creek Generating Station (ADAMS Accession Number ML052080185). The applicant requested renewal of its operating license for an additional 20 years beyond the 40-year current license term.

Included in the applicant's LRA was the Oyster Creek Station Blackout System Combustion Turbine, located in Forked River, New Jersey. Subsequent to submitting the LRA, the applicant revised its approach to aging management for the Forked River Combustion Turbine (FRCT), the radio communications system, and the meteorological tower (Met tower). Specifically, the applicant has taken a more detailed approach to scoping, screening, aging management reviews, and aging management programs for the components within these systems.

The more detailed approach for the Forked River combustion turbine is described in the following two AmerGen submittals, which supplement the Oyster Creek license renewal application:

- AmerGen Letter 2130-05-20214, ?Response to NRC Request for Additional Information (RAI 2.5.1.19-1), dated September 28, 2005, Related to Oyster Creek Generating Station License Renewal Application (TAC No. MC7624)," dated October 12, 2005, and
- AmerGen Letter 2130-05-20228, ?Supplemental Response to NRC Request for Additional Information (RAI 2.5.1.19-1), dated September 28, 2005, Related to Oyster Creek Generating Station License Renewal Application (TAC No. MC7624), dated November 11, 2005.

The more detailed approach for the radio communications system and the Met tower is described in the following AmerGen submittal, which supplements the Oyster Creek license renewal application:

- AmerGen Letter 2130-05-20239, ?Response to NRC Request for Additional Information (RAI-2.5.1.15-1) dated November 9, 2005, Related to Oyster Creek Generating Station License Renewal Application (TAC No. MC7624)," dated December 9, 2005.

In support of the staff's safety review of the license renewal application (LRA) for Oyster Creek Generating Station (OCGS), the License Renewal Branch C (RLRC) led a project team that audited and reviewed selected AMRs and associated AMPs developed by the applicant to support the LRA for OCGS. The project team included both NRC staff and contractor personnel provided by Brookhaven National Laboratory (BNL), the RLRC technical contractor. Attachment 2 of this audit and review report lists the project team members, as well as other NRC staff and BNL personnel who supported the project team's audit and review.

The aging management reviews and aging management programs credited for the FRCT, radio communications system, and Met tower were reviewed as part of the OCGS LRA audit. The project team performed its work in accordance with the same requirements used for the OCGS audit, as described in Section 1 of this audit and review report.

This Attachment to the audit and review report documents the results of the project team's audit and review work for the FRCT, radio communications system, and Met tower. Attachment 2 of this audit and review report lists the applicant personnel and other individuals contacted by the project team in support of the work documented in this Attachment.

A7.1.2 Background

The background information presented in Section 1.2 of this audit and review report for the OCGS LRA audit and review also applies to the FRCT, radio communications system, and Met tower audit and review.

A7.2 Audit and Review Scope

The AMRs and associated AMPs that the project team reviewed are identified in the OCGS audit and review plan. The project team examined 12 AMPs that specifically address FRCT, radio communications system, and Met tower components and systems in the scope of license renewal, along with revisions to two OCGS AMPs that are used for these systems, as well as associated AMRs. The project team reviewed AMPs and AMRs that the applicant claimed were consistent with the GALL Report, and AMRs for which further evaluation is recommended by the GALL Report. The project team also reviewed certain plant-specific AMPs.

The applicant noted that some of its AMPs, although described as consistent with the GALL Report, contain some deviations from the GALL Report. These deviations are the same as those discussed in Section 2 of this audit and review report for the OCGS LRA.

The project team's audit and review activities for the FRCT, radio communications system, and Met tower AMPs, and its conclusions regarding these reviews, are documented in Sections A7.3.0.3 of this Attachment to the audit and review report.

The project team also reviewed all FRCT, radio communications system, and Met tower Table 2 AMR line-items. The project team reviewed the AMR results, reported by the applicant to be consistent with the GALL Report, to determine whether they are consistent with the GALL Report. For AMR results for which the GALL Report recommends further evaluation, the project team reviewed the applicant's evaluation to determine whether it adequately addresses the issues for which the GALL Report recommends further evaluation.

In Tables 3.6.2.1.2A (FRCT electrical) and 3.6.2.1.2C (FRCT structural) of AmerGen Letter 2130-05-20214, Table 3.6.2.1.2B (FRCT mechanical) of AmerGen Letter 2130-05-20228, and Tables 3.5.2.1.20 (Met tower structural) and 3.6.2.1.3 (radio communications system) of AmerGen Letter 2130-05-20239, in addition to the notes, the applicant provided a summary of AMR results for the applicable systems, which included the SCs, associated materials, environment, any aging effects requiring management, and an AMP for each line-item. The notes describe how the information in the tables aligns with the information in the GALL Report. Those that are aligned with the GALL Report are assigned letters and are described in Section 2 of this audit and review report. Those defined by the applicant are assigned numbers and are defined in the FRCT license renewal submittals.

Discrepancies or issues discovered by the project team during the audit and review that required a response are documented in this Attachment to the audit and review report. If an issue was not resolved prior to issuing this audit and review report, a request for additional information (RAI) was prepared by the project team to solicit the information needed to resolve the issue.

The RAI will be included and dispositioned in the safety evaluation report (SER) related to the OCGS LRA. A list of RAIs associated with the audit is provided in Attachment 4 to this audit and review report.

The project team's audit and review activities for the FRCT, radio communications system, and Met tower AMRs, and its conclusions resulting from these activities, are documented in Sections A7.3.1 through A7.3.3 of this Attachment to the audit and review report.

A7.3. Aging Management Review Audit and Review Results

This section of the Attachment to the audit and review report contains the project team's evaluation of the FRCT, radio communications system, and Met tower AMPs and AMRs. In the FRCT, radio communications system, and Met tower license renewal submittals, the applicant described the AMPs that it relies on to manage or monitor the aging of long-lived, passive components and structures. The applicant also provided the results of the AMRs for those structures and components that it identifies as being within the scope of license renewal and subject to an AMR.

A7.3.0 Use of the Generic Aging Lessons-Learned Report

In preparing its FRCT, radio communications system, and Met tower aging management reviews and aging management programs, AmerGen credited the GALL Report in the same manner as described in Section 3.0 of this audit and review report for the OCGS LRA.

A7.3.0.1 Format of the FRCT License Renewal Information

The FRCT, radio communications system, and Met tower license renewal information follows the same format used for the OCGS LRA, which is described in Section 3.0.1 of this audit and review report.

A7.3.0.1.1 *Overview of FRCT Table 1*

FRCT Table 1s (Tables 3.6.1A, 3.6.1B, and 3.6.1C), as well as the radio communications system and Met tower Table 1 (Table 3.6.1D), provide a summary comparison of how the FRCT, radio communications system, and Met tower AMR results align with the corresponding tables of the GALL Report. They follow the same format used for the OCGS LRA, as described in Section 3.0.1.1 in this audit and review report.

A7.3.0.1.2 *Overview of OCGS LRA Table 2*

FRCT Table 2s (Tables 3.6.2.1.2A, 3.6.2.1.2B, and 3.6.2.1.2C), as well as radio communications system and Met tower Table 2s (Tables 3.5.2.1.20 and 3.6.2.1.3) provide the detailed results of the AMRs for those components identified as being subject to an AMR. There is a Table 2 for each of the components or systems within a system grouping. The Table 2s consists of the same information contained in the OCGS LRA Table 2s, as described in Section 3.0.1.2 of this audit and review report.

A7.3.0.2 Audit and Review Process

The project team performed the audit and review in accordance with the criteria defined in Revision 1 of NUREG-1800, ?Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," (SRP-LR). Additional details on how the SRP-LR criteria were addressed are provided in the OCGS audit and review plan. This review process is summarized in Section 3.0.2 of this audit and review report.

A7.3.0.3 OCGS Aging Management Programs

The project team's audit and review activities for the FRCT, radio communications system, and Met tower AMPs and its conclusions regarding these programs are documented below.

Table A7-1, FRCT, Radio Communications System, and Met Tower Aging Management Programs, presents the AMPs credited by the applicant and described in the following documents:

- *Structural and Electrical AMPs*: Appendix D of the Enclosure to AmerGen letter ?Response to NRC Request for Additional Information (RAI 2.5.1.19-1), dated September 28, 2005, Related to Oyster Creek Generating Station License Renewal Application (TAC No. MC7624)," dated October 12, 2005, and
- *Mechanical AMPs*: Appendix D of the Enclosure to AmerGen letter ?Supplemental Response to NRC Request for Additional Information (RAI 2.5.1.19-1), dated September 28, 2005, Related to Oyster Creek Generating Station License Renewal Application (TAC No. MC7624), dated November 11, 2005.

Table A7-1 also indicates the GALL Report program to which the applicant claimed its AMP was consistent (if applicable), and the SSCs for which the AMP is credited for managing or monitoring aging. The section of this Attachment to the audit and review report in which the project team's evaluation of the program is documented is also provided.

Table A7-1 FRCT, Radio Communications System, and Met Tower Aging Management Programs

FRCT/RC/MT AMP (ID No.)	GALL Report Comparison	GALL Report AMP(s)	FRCT/RC/MT Systems or Structures that Credit the AMP	Project Team's Evaluation Section
Bolting Integrity – FRCT (B.1.12A)	Consistent with exceptions	XI.M18, Bolting Integrity	FRCT Mechanical Systems	A7.3.0.3.2.1
Closed-Cycle Cooling Water System – FRCT (B.1.14A)	Consistent with exception	XI.M21, Closed-Cycle Cooling Water System	FRCT Mechanical Systems	A7.3.0.3.2.2
Aboveground Outdoor Tanks – FRCT (B.1.21A)	Consistent with exception	XI.M29, Above Ground Carbon Steel Tanks	FRCT Mechanical Systems	A7.3.0.3.2.3
Fuel Oil Chemistry – FRCT (B.1.22A)	Consistent with exceptions	XI.M30, Fuel Oil Chemistry	FRCT Mechanical Systems	A7.3.0.3.2.4
One-Time Inspection – FRCT (B.1.24A)	Consistent with exceptions	XI.M32, One-Time Inspection	FRCT Mechanical Systems	A7.3.0.3.2.1
Selective Leaching of Materials – FRCT	Consistent with exceptions	XI.M33, Selective Leaching of Materials	FRCT Mechanical Systems	A7.3.0.3.2.6

FRCT/RC/MT AMP (ID No.)	GALL Report Comparison	GALL Report AMP(s)	FRCT/RC/MT Systems or Structures that Credit the AMP	Project Team's Evaluation Section
(B.1.25A)				
Buried Piping Inspection – FRCT (B.1.26A)	Consistent with exceptions	XI.M34, Buried Piping and Tanks Inspection	FRCT Mechanical Systems Radio Comm. Sys.	A7.3.0.3.2.7
Structures Monitoring Program (B.1.31)	Consistent with enhancements	XI.S6, Structures Monitoring Program	FRCT Mechanical Systems FRCT Electrical Systems FRCT Structural Systems Met Tower Structural Sys. Radio Com. Sys.	A7.3.0.3.2.8
Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.1.36)	Consistent with exceptions	XI.E3, Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	FRCT Electrical Systems	A7.3.0.3.2.9
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components – FRCT (B.1.38)	Consistent with exceptions	XI.M38 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	FRCT Mechanical Systems	A7.3.0.3.2.10
Lubricating Oil Analysis – FRCT (B.1.39)	Consistent with exceptions	XI.M39 Lubricating Oil Analysis Program	FRCT Mechanical Systems	A7.3.0.3.2.11
Periodic Monitoring of Combustion Turbine Power Plant Electrical (B.1.37)	N/A	Oyster Creek plant-specific program	FRCT Electrical Systems	A7.3.0.3.3.1
Periodic Inspection Program – FRCT (B.2.5A)	N/A	Oyster Creek plant-specific program	FRCT Mechanical Systems	A7.3.0.3.3.2
Buried Piping Inspection-Met Tower (B.1.26B)	Consistent with exceptions	XI.M34, Buried Piping and Tanks Inspection	Met Tower Mechanical Systems	A7.3.0.3.2.12

A7.3.0.3.1 ***AMPs That Are Consistent with the GALL Report***

None.

A7.3.0.3.2 ***AMPs That Are Consistent with the GALL Report with Exceptions and/or Enhancements***

A7.3.0.3.2.1 Bolting Integrity – FRCT (B.1.12A)

In the applicant's response to NRC RAI 2.5.1.19-1 related to the OCGS LRA, dated November 11, 2005, Appendix D, Section B.1.12A, the applicant stated that OCGS AMP B.1.12A, ?Bolting Integrity – FRCT," aging management program is a new program that is consistent with GALL AMP XI.M18, ?Bolting Integrity," with exceptions.

A7.3.0.3.2.1.1 Program Description

In their response to RAI 2.5.1.19-1, the applicant stated that this program will be used for condition monitoring of bolts and bolted joints within the scope of license renewal at the Forked River Combustion Turbine station. The Forked River Combustion Turbine power plant was originally designed and supplied by General Electric Company. This program is based on the General Electric recommendations for proper bolting material selection, lubrication, preload application, installation and maintenance associated with the combustion turbine units and auxiliary systems. The program also includes periodic walkdown inspections for bolting degradation or bolted joint leakage. The program manages the loss of bolting function, including loss of material and loss of preload aging effects. Bolted joint inspections rely on detection of visible leakage during routine observations and equipment maintenance activities.

A7.3.0.3.2.1.2 Consistency with the GALL Report

In their response to RAI 2.5.1.19-1, the applicant stated that the OCGS AMP B.1.12A is consistent with the GALL XI.M.18, with exceptions.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.12A, including the program bases document PBD-AMP-B.1.12A, ?Bolting Integrity – FRCT," Revision 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M18. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.12A and associated bases documents to determine consistency with GALL AMP XI.M18.

The project team reviewed those portions of the Bolting Integrity program for which the applicant claims consistency with GALL AMP XI.M18 and found that they are consistent with the GALL Report AMP. The project team found the applicant's Bolting Integrity – FRCT conforms to the recommended GALL AMP XI.M18, with exceptions as described below.

A7.3.0.3.2.1.3 Exceptions to the GALL Report

In their response to RAI 2.5.1.19-1, the applicant stated the following exceptions to the GALL Report program elements:

Exception 1

Elements :	1. Scope of Program 2. Preventive Actions 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring and Trending 6. Acceptance Criteria
Exception:	The Bolting Integrity – FRCT program does not specifically incorporate NRC and industry recommendations delineated in NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants." The program also does not specifically address Electric Power Research Institute (EPRI) NP-5769 for safety-related bolting, or EPRI TR-104213. These documents were developed specifically for the nuclear power industry. The Forked River Combustion Turbine station is a non-nuclear fossil-fueled station. The Bolting Integrity – FRCT program was evaluated against the ten elements of aging management program XL.M18, "Bolting Integrity," specified in NUREG-1801. Each element is evaluated, and the associated portions of the element that are applicable to the Forked River Combustion Turbine power plant have been incorporated into this program. This program applies good industry bolting practices based on General Electric (the original FRCT designer and supplier) recommendations, supplemented with periodic walkdown inspections to confirm bolting integrity. The requirements for safety-related bolting, and bolting for nuclear steam supply system component supports, do not apply to the Forked River Combustion Turbine power plant.

The GALL Report identified the following recommendations for the program elements ?scope of program,” ?preventive actions,” ?parameters monitored or inspected,” ?detection of aging effects,” ?monitoring and trending” and ?acceptance criteria” associated with the exception taken:

1. *Scope of Program*: This program covers bolting within the scope of license renewal, including: 1) safety-related bolting, 2) bolting for nuclear steam supply system (NSSS) component supports, 3) bolting for other pressure retaining components, including non-safety-related bolting, and 4) structural bolting (actual measured yield strength ³ 150 ksi). The aging management of Reactor Head Closure Studs is addressed by XI.M3, and is not included in this program. The staff’s recommendations and guidelines for comprehensive bolting integrity programs that encompass all safety-related bolting are delineated in NUREG-1339, which include the criteria established in the 1995 edition through the 1996 addenda of ASME Code Section XI. The industry’s technical basis for the program for safety-related bolting and guidelines for material selection and testing, bolting preload control, ISI, plant operation, and maintenance, and evaluation of the structural integrity of bolted joints, are outlined in EPRI NP-5769, with the exceptions noted in NUREG-1339. For other bolting, this information is set forth in EPRI TR-104213.

2. *Preventive Actions*: Selection of bolting material and the use of lubricants and sealants is in accordance with the guidelines of EPRI NP-5769, and the additional recommendations of NUREG-1339, to prevent or mitigate degradation and failure of safety-related bolting. NUREG-1339 takes exception to certain items in EPRI NP-5769, and recommends additional measures with regard to them. Bolting replacement activities include proper torquing of the bolts and checking for uniformity of the gasket compression after assembly. Maintenance practices require the application of an appropriate preload, based on EPRI documents.

3. *Parameters Monitored or Inspected*: This program monitors the effects of aging on the intended function of bolting. Specifically, bolting for safety-related pressure retaining components is inspected for leakage, loss of material, cracking, and loss of preload/loss of prestress. Bolting for other pressure retaining components is inspected for signs of leakage. High strength bolts (actual yield strength >150 ksi) used in NSSS component supports are monitored for cracking. Structural bolts and fasteners are inspected for indication of potential problems including loss of material, cracking, loss of coating integrity, and obvious signs of corrosion, rust, etc.

4. *Detection of Aging Effects*: Inspection requirements are in accordance with the ASME Section XI, Tables IWB 2500-1, IWC 2500-1 and IWD 2500-1 editions endorsed in 10 CFR 50.55a(b)(2) and the recommendations of EPRI NP-5769. For Class 1 components, Table IWB 2500-1, Examination Category B-G-1, for bolts greater than 2-inches in diameter, specifies volumetric examination of studs and bolts and visual VT-1 examination of surfaces of nuts, washers, bushings, and flanges. Examination Category B-G-2, for bolts 2-inches or smaller, requires only visual VT-1 examination of surfaces of bolts, studs, and nuts. For Class 2 components, Table IWC 2500-1, Examination Category C-D, for bolts greater than 2-inches in diameter, requires volumetric examination of studs and bolts. Examination Categories B-P, C-H, and D-B require visual examination (IWA-5240) during system leakage testing of all pressure-retaining Class 1, 2 and 3 components, according to Tables IWB 2500-1, IWC 2500-1, and IWD 2500-1, respectively. In addition, degradation of the closure bolting due to crack initiation, loss of prestress, or loss of material due to corrosion of the closure bolting would result in leakage. The extent and schedule of inspections, in accordance with Tables IWB 2500-1, IWC 2500-1, and IWD 2500-1, combined with periodic system walkdowns, assure detection of leakage before the leakage becomes excessive. For other pressure retaining bolting, periodic system walkdowns assure detection of leakage before the leakage becomes excessive. High strength structural bolts and fasteners (actual yield strength 150 ksi) for NSSS component supports, may be subject to stress corrosion cracking (SCC). For this type of high strength structural bolts that are potentially subjected to SCC, in sizes greater than 1-inch nominal diameter, volumetric examination comparable to that of Examination Category B-G-1 is required in addition to visual examination. This requirement may be waived with adequate plant-specific justification. Structural bolts and fasteners (actual yield strength < 150 ksi) both inside and outside containment are inspected by visual inspection (e.g., Structures Monitoring Program or equivalent). In addition to visual and volumetric examination, degradation of these bolts and fasteners may be detected and measured by removing the bolt/fastener, a proof test by tension or torquing, in situ ultrasonic tests, or a hammer test. If these bolts and fasteners are found

cracked and/or corroded, a closer inspection is performed to assess the extent of corrosion. An appropriate technique is selected on the basis of the bolting application and the applicable code.

5. *Monitoring and Trending*: The inspection schedules of ASME Section XI are effective and ensure timely detection of applicable aging effects. If bolting connections for pressure retaining components (not covered by ASME Section XI) is reported to be leaking, then it may be inspected daily. If the leak rate does not increase, the inspection frequency may be decreased to biweekly or weekly.

6. *Acceptance Criteria*: Any indications of aging effects in ASME pressure retaining bolting are evaluated in accordance with Section XI of the ASME Code. For other pressure retaining bolting, NSSS component support bolting and structural bolting, indications of aging should be dispositioned in accordance with the corrective action process.

The applicant stated, in their response to RAI 2.5.1.19-1 and in the basis document PBD-AMP-B.1.12A, the following:

The scope of the program covers bolting within the scope of license renewal at the Forked River Combustion Turbine power plant. There is no safety-related bolting or bolting for nuclear steam supply system (NSSS) component supports at the Forked River Combustion Turbine power plant. The program scope includes pressure-retaining component bolting and structural bolting used on the Forked River combustion turbine units and auxiliary systems and structures in the scope of license renewal. The Forked River Combustion Turbine power plant was originally designed and supplied by General Electric Company, and this program is based on the General Electric recommendations for proper bolting application and maintenance associated with the combustion turbine units and auxiliary systems.

For preventive actions, selection of bolting material and the use of lubricants and sealants is in accordance with the recommendations provided by General Electric. The GE Inspection and Maintenance manual for the units prescribe the specific sealants and lubricants to be used, and how and where they are applied. Bolting replacement activities include proper torquing of the bolts, proper alignment of flanges, and checking for proper mating surface contact after assembly based on the specific joint classification. Maintenance practices require the application of an appropriate preload, as specified in the General Electric Inspection and Maintenance Instructions for the combustion turbine units. Preload of gasketed joints is controlled by torque wrench or by measurement of bolt or stud elongation. Preload of joints with metal-to-metal contact is controlled by torque wrench, by measurement of bolt or stud elongation, or by head rotation.

For parameters monitored or inspected, this program monitors the effects of aging on the intended function of bolting associated with the Forked River Combustion Turbine power plant. There are no safety-related pressure retaining components or NSSS component supports at the Forked River Combustion Turbine power plant. Pressure retaining bolting at the Forked River Combustion Turbine power plant will be periodically inspected for signs of leakage. Other bolting will be inspected for signs of significant degradation including loss of material, loss of coating integrity, and obvious signs of corrosion, rust, or loose or missing bolts.

For detection of aging effects, degradation of the pressure retaining closure bolting due to crack initiation, loss of prestress, or loss of material due to corrosion of the closure bolting would result in leakage. Periodic plant walkdowns will assure detection of leakage before the leakage becomes excessive such that the intended function of the Forked River Combustion Turbine power plant would be impacted. In addition to leakage detection, plant walkdowns will include inspection of bolting for signs of significant degradation including loss of material, loss of coating integrity, and obvious signs of corrosion, rust, or loose or missing bolts.

For monitoring and trending, walkdown inspections for leakage and inspections for bolting degradation will be performed at least once every four years. Identified leakage will be monitored daily until repaired. Much of the equipment at the Forked River Combustion Turbine power plant is located outdoors, so even small leaks must be immediately isolated or repaired because of potential environmental concerns. If continued leakage is acceptable under the applicable permits and regulations, and if the leak rate does not increase, the inspection frequency may be decreased to biweekly or weekly.

For acceptance criteria, any indications of leaking pressure retaining bolting, or bolting degradation that could potentially lead to loss of system or component intended functions, will be evaluated and dispositioned in accordance with the corrective action process described below.

The project team noted that there are no safety-related components or nuclear steam supply system support components that support the operation of Forked River Combustion Turbine station and hence the guidance for the ASME Section XI inspection requirements, selection of bolting material and the use of lubricants and sealants contained in NUREG-1339, EPRI TR-104213, and EPRI NP-5769 does not apply to the FRCT power plant. On this basis, the project team found this exception acceptable.

<u>Exception 2</u>

Elements:	7. Corrective Actions 8. Confirmation Process 9. Administrative Controls
Exception:	These elements are not accomplished in accordance with the AmerGen quality assurance (QA) program and are not in accordance with the requirements of 10 CFR Part 50, Appendix B.

The GALL Report identified the following recommendations for the above program elements associated with the exception taken:

> The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with 10 CFR Part 50, Appendix B. The staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

The adequacy of the applicant's Quality Assurance Program associated with this program element is reviewed by DE staff and addressed in Section 3.0 of the SER related to the OCGS LRA. In their response to RAI 2.5.1.19-1, the applicant stated that it will meet the guidance in Branch Technical Position IQMB-1, ?Branch Technical Position ?Quality Assurance for Aging Management Programs." On this basis, the project team found this exception acceptable.

A7.3.0.3.2.1.14 Enhancements

None.

A7.3.0.3.2.1.15 Operating Experience

The applicant stated in their response to NRC RAI 2.5.1.19-1 that in March 2004 (Unit 1 FRCT), GE Energy Services performed major inspection and maintenance activities and documented all work performed in an inspection reports dated June 7, 2004. The equipment inspections included the turbine and its internals and support equipment. All work was carried out closely following the instructions and guidance found in the original equipment manufacturer's design, maintenance and inspection manuals. Acceptance criteria and corrective actions for these activities ensure that equipment is maintained within design specifications.

The Unit 1 inspection was a major maintenance inspection. This was the first major inspection that was performed on the unit since initial installation in 1988. During final alignment of the load gear following the major inspection, three load gear anchor bolt studs failed. The cause of the failure was determined to be improper initial installation. All anchor bolt studs were repaired by welding new studs in place. The anchor bolts had not failed during the sixteen years of operation prior to the major outage.

There is no history of bolted joint failures resulting in loss of intended function of the combustion turbine units. Damaged and missing bolts have been identified in the hot exhaust gas plenum, but the exhaust system structural integrity was not compromised and the unit operability and reliability was not affected. Critical bolting associated with the combustion turbine assembly is inspected during maintenance inspections and replaced if required.

Numerous bolts and bolted joints were visually observed during walkdowns conducted during the combustion turbine Unit 2 major inspection outage that began in October 2005. Bolted joints, including pipe flanges, ventilation joints, pump casings and valve bonnets, were observed in indoor and outdoor environments, and were found to be in good condition with no signs of significant degradation or missing or loose bolts. Minor surface rust was observed on some outdoor bolting. The coating of painted bolting was observed to be in good condition. Bolting was observed on Unit 1, Unit 2, and common auxiliary systems.

The operating experience with the Forked River combustion turbines includes a significant number of past inspection activities that included observations of bolting and bolted joints. The documented inspection results provide objective evidence that existing environmental conditions are not resulting in significant bolting degradation that could result in a loss of the bolting intended functions. Past inspections have been performed at a various frequencies, as long as 16 years for some components, with the units performing reliably between inspections. Implementation of this new program will assure that proper bolting maintenance practices are continued, and that walkdown inspections for leakage and inspections for bolting degradation will be performed at least once every four years, providing assurance that the aging effects will be adequately managed for the period of extended operation.

The project team reviewed the operating experience provided in the basis document, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant's Bolting Integrity – FRCT program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

A7.3.0.3.2.1.16 UFSAR Supplement

The applicant provided its UFSAR Supplement for the Bolting Integrity – FRCT program in their response to NRC RAI 2.5.1.19-1, which stated that the Bolting Integrity – FRCT program is a new program that provides for condition monitoring of bolts and bolted joints within the scope of license renewal at the Forked River Combustion Turbine power plant. The Forked River Combustion Turbine power plant was originally designed and supplied by General Electric Company. This program is based on the General Electric recommendations for proper bolting material selection, lubrication, preload application, installation and maintenance associated with the combustion turbine units and auxiliary systems. The program also includes periodic walkdown inspections for bolting degradation or bolted joint leakage at a frequency of at least once every four years. The program manages the loss of material and loss of preload aging effects. This new program will be implemented prior to entering the period of extended operation.

The project team also reviewed the applicant's updated license renewal commitment list in Appendix A of the November 11, 2006 supplemental response to RAI 2.5.1.19-1, and confirmed that this program is identified as a new program that will be implemented prior to the period of extended operation as item 51 of the commitments.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant's Bolting Integrity – FRCT program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.12A found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

A7.3.0.3.2.1.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report, are consistent with the GALL Report. In addition, the project team has reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. The project team also reviewed the UFSAR Supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

A7.3.0.3.2.2 Closed-Cycle Cooling Water System – FRCT (B.1.14A)

In the November 11, 2005, supplemental response to NRC RAI 2.5.1.19-1, Appendix D, Section B.1.14A, the applicant stated that OCGS AMP B.1.14A, "Closed-Cycle Cooling Water System – FRCT," is a new program that is consistent with GALL AMP XI.M21, "Closed-Cycle Cooling Water System," with two exceptions and an enhancement.

A7.3.0.3.2.2.1 Program Description

In the November 11, 2005, supplemental response to NRC RAI 2.5.1.19-1, the applicant stated that this program manages aging of pumps, tanks, piping, piping components, piping elements and heat exchangers that are included in the scope of license renewal and are exposed to a closed cooling water environment at the Forked River combustion turbine power plant. This program incorporates experience with existing activities associated with the closed cooling water system, performed at the Forked River combustion turbine power plant. The closed cooling water environment at the Forked River combustion turbine power plant is a blended water-glycol based environment. This program includes preventive measures to minimize corrosion and SCC, and performance monitoring and maintenance inspection activities to monitor the effects of corrosion and SCC on the intended function of the components.

Preventive activities rely on maintenance of appropriate water chemistry control parameters within the specified limits of Electric Power Research Institute (EPRI) TR-1007820, ?Closed Cooling Water Chemistry Guideline," Revision 1, for blended glycol formulations, to minimize corrosion and SCC. These control parameters include percent glycol or freeze point, and pH. EPRI TR-1007820 does not require monitoring of system corrosion inhibitor concentrations for blended glycol formulations, unless corrosion inhibitors have been added. If corrosion inhibitors are added, then EPRI TR-1007820 Section 5.9 recommends that the corrosion inhibitor concentrations be monitored to within the range recommended by the corrosion inhibitor manufacturer. The FRCT closed-cycle cooling water system utilizes a proprietary inhibited glycol product and does not add supplemental corrosion inhibitors.

The applicant also stated that performance monitoring provides indications of degradation in closed-cycle cooling water systems, with plant operating conditions providing indications of degradation in frequently operated systems. In addition, station maintenance inspections provide condition monitoring of heat exchangers exposed to closed-cycle cooling water environments. These measures will ensure that the intended functions of the systems and components serviced by the closed cooling water system are not compromised by aging.

A7.3.0.3.2.2.2 Consistency with the GALL Report

In the November 11, 2005, supplemental response to NRC RAI 2.5.1.19-1, the applicant stated that the closed-cycle cooling water – FRCT AMP-B.1.14A is consistent with GALL AMP XI.M21, with two exceptions and an enhancement.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for the closed-cycle cooling water – FRCT AMP-B.1.14A, including program basis document PBD-AMP-B.1.14A, ?Closed Cycle Cooling Water – FRCT," Rev. 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M21. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in the closed-cycle cooling water – FRCT program basis document PBD-AMP-B.1.14A and associated bases documents to determine their consistency with GALL AMP XI.M21.

The project team reviewed those portions of the closed-cycle cooling water – FRCT aging management program for which the applicant claims consistency with GALL AMP XI.M21 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's closed-cycle cooling water – FRCT aging management program conforms to the recommended GALL AMP XI.M21, with the exceptions and enhancement described below.

A7.3.0.3.2.2.3 Exceptions to the GALL Report

In the November 11, 2005, supplemental response to NRC RAI 2.5.1.19-1, the applicant stated the following exceptions to the GALL Report program elements:

Exception 1

Elements: 2. Preventive Actions
3. Parameters Monitored or Inspected
5. Monitoring and Trending
6. Acceptance Criteria

Exception: NUREG 1801 refers to EPRI TR-107396 ?Closed Cooling Water Chemistry Guidelines" 1997 Revision. Oyster Creek implements the guidance provided in EPRI 1007820 "Closed Cooling Water Chemistry Guideline," Revision 1, which is the 2004 Revision to TR-107396. EPRI periodically updates industry water chemistry guidelines, as new information becomes available. Oyster Creek has reviewed EPRI 1007820 and has determined that the most significant difference is that the new revision provides more prescriptive guidance and has a more conservative monitoring approach. EPRI 1007820 meets the same recommendations of EPRI TR-107396 for maintaining conditions to minimize corrosion and microbiological growth in closed cooling water systems for effectively mitigating many aging effects.

The GALL Report identified the following recommendations for the ?preventive actions," ?parameters monitored or inspected," ?monitoring and trending," and ?acceptance criteria" program elements associated with the exception taken:

2. *Preventive Actions:* The program relies on the use of appropriate materials, lining, or coating to protect the underlying metal surfaces and maintain system corrosion inhibitor concentrations within the specified limits of EPRI TR-107396 to minimize corrosion and SCC.

3. *Parameters Monitored or Inspected*: The aging management program monitors the effects of corrosion and SCC by testing and inspection in accordance with guidance in EPRI TR-107396 to evaluate system and component condition.

5. *Monitoring and Trending*: In accordance with EPRI TR-107396, internal visual inspections and performance/functional tests are to be performed periodically to demonstrate system operability and confirm the effectiveness of the program.

6. *Acceptance Criteria*: Corrosion inhibitor concentrations are maintained within the limits specified in the EPRI water chemistry guidelines for CCCW. (NUREG 1801 refers to EPRI TR-107396 for control of water chemistry).

In reviewing this exception, the project team noted that in Section 2.2 of the program basis document, PBD-AMP-B.1.14A, ?Closed-Cycle Cooling Water," Rev. 0, the paragraph titled ?Summary of Exceptions to NUREG-1801" described the above exception related to the use of

EPRI TR-107396, ?Closed Cooling Water Chemistry Guidelines" (1997 revision). However, this exception was not identified or discussed in the Section 3.0 of the program basis document, which contains the evaluation of the individual GALL aging management program elements. The applicant stated that PBD-AMP-B.1.14A will be revised to include this exception in the program basis document Section 3.0 evaluation of the individual GALL aging management program elements.

The applicant stated that the program basis document, PBD-AMP-B.1.14A, for the closed-cycle cooling water – FRCT aging management program will be revised to address the exception to the use of EPRI TR-107396, ?Closed Cooling Water Chemistry Guidelines," in the evaluation of the individual program elements in Section 3.0 of the program basis document.

As part of the audit, the project team interviewed the applicant's technical staff to discuss technical issues related to this exception. During the interview, the applicant described its review and evaluation of the differences between EPRI TR-107396, ?Closed Cooling Water Chemistry Guidelines," the 1997 revision of the guidelines referred to in NUREG-1801, and EPRI TR-1007820, ?Closed Cooling Water Chemistry Guideline," Revision 1, which is the 2004 revision implemented by Oyster Creek. The applicant stated that the most significant difference from the original version of the closed cooling water chemistry guidelines document is that EPRI TR-1007820 provides more prescriptive guidance and has a more conservative monitoring approach. The applicant further stated that EPRI TR-1007820 meets the same recommendations of EPRI TR-107396 for maintaining conditions to minimize corrosion and microbiological growth in closed cooling water systems for effectively mitigating many aging effects.

In addition, the applicant stated that as part of its comparative review of the guidelines documents it had contacted Anthony Selby, the author of EPRI TR-107396 and EPRI TR-1007820, to confirm that the new guidance that was provided in TR-1007820 was not contrary to the guidance in TR-107396.

The project team reviewed EPRI TR-1007820, ?Closed Cooling Water Chemistry Guideline," Revision 1, and EPRI TR-107396 (Revision 0) and confirmed the applicant's assessment that the new revision provides more prescriptive guidance, has a more conservative monitoring approach, and meets the same requirements for maintaining conditions to minimize corrosion and microbiological growth in closed cooling water systems for effectively mitigating many aging effects. On this basis, the project team found this exception acceptable.

<u>Exception 2</u>

Elements:	7. Corrective Actions 8. Confirmation Process 9. Administrative Controls
Exception:	These elements are not accomplished in accordance with the AmerGen quality assurance (QA) program and are not in accordance with the requirements of 10 CFR Part 50, Appendix B.

The GALL Report identified the following recommendations for the above program elements associated with the exception taken:

> The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with 10 CFR Part 50, Appendix B. The staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

The adequacy of the applicant's Quality Assurance Program associated with this program element is reviewed by DE staff and addressed in Section 3.0 of the SER related to the OCGS LRA. In their response to RAI 2.5.1.19-1, the applicant stated that it will meet the guidance in Branch Technical Position IQMB-1, ?Quality Assurance for Aging Management Programs." On this basis, the project team found this exception acceptable.

A7.3.0.3.2.2.4 Enhancements

In the November 11, 2005, supplemental response to NRC RAI 2.5.1.19-1, the applicant stated identified the following enhancement in order to meet meeting the GALL Report program elements:

Element:	1. Scope of Program
Enhancement:	The closed-cycle cooling water – FRCT aging management program is a new program to be implemented for the components in the scope of license renewal and subject to a closed cycle cooling water environment located at the Forked River combustion Turbine power plant.

The GALL Report identified the following recommendation for the ?scope of program" element associated with the enhancement:

> 1. *Scope of Program*: A CCCW system is defined as part of the service water system that is not subject to significant sources of contamination, in which water chemistry is controlled, and in which heat is not directly rejected to a heat sink.

In reviewing this enhancement, the project team noted that in Section 2.2 of the program basis document PBD-AMP-B.1.14A,?Closed-Cycle Cooling Water," Rev. 0, the paragraph titled ?Summary of Enhancements to NUREG-1801" stated that the closed-cycle cooling water – FRCT aging management program is a new program to be implemented for the components in the scope of license renewal and subject to a closed cycle cooling water environment located at the Forked River combustion Turbine power plant. However, this enhancement was not identified or discussed in the Section 3.0 evaluation of the individual GALL aging management program elements. The applicant stated that PBD-AMP-B.1.14A will be revised to include this enhancement in the program basis document Section 3.0 evaluation of the individual GALL aging management program elements.

The applicant stated that the program basis document, PBD-AMP-B.1.14A, for the closed-cycle cooling water – FRCT aging management program will be revised to address the enhancement to develop the new closed-cycle cooling water – FRCT aging management program in the evaluation of the individual program elements, in Section 3.0 of the program basis document.

In the November 11, 2005, supplemental response to NRC RAI 2.5.1.19-1, the applicant stated that this program manages aging of pumps, tanks, piping, piping components, piping elements and heat exchangers that are included in the scope of license renewal and are exposed to a closed cooling water environment at the Forked River combustion turbine power plant. This program incorporates experience with existing activities associated with the closed cooling water system, performed at the Forked River combustion turbine power plant. The closed cooling water environment at the Forked River combustion turbine power plant is a blended water-glycol based environment. This program includes preventive measures to minimize corrosion and SCC, and performance monitoring and maintenance inspection activities to monitor the effects of corrosion and SCC on the intended function of the components; therefore, the project team determined that this new program is acceptable.

On this basis, the project team found this enhancement acceptable since when the enhancement is implemented, OCGS AMP-B.1.14A, "Closed-Cycle Cooling Water – FRCT," will be consistent with GALL AMP XI.M21 and will provide additional assurance that the effects of aging will be adequately managed.

A7.3.0.3.2.2.5 Operating Experience

In the November 11, 2005, supplemental response to NRC RAI 2.5.1.19-1, the applicant stated that the Forked River combustion turbine power plant has not experienced a loss of intended function failure of components due to corrosion product buildup, through-wall loss of material, or SCC for components within the scope of license renewal that are subject to a closed-cycle cooling water environment.

The Forked River combustion turbine units undergo periodic major inspection outages in accordance with manufacturer's recommendations. In March 2004 (Unit 1 combustion turbine), GE Energy Services performed major inspection and maintenance activities and documented all work performed in an inspection report dated June 7, 2004. In October 2005 GE began a major inspection and maintenance outage on the Unit 2 combustion turbine. The scope of equipment inspections included the turbine and its internals and support equipment. Acceptance criteria and corrective actions for these activities ensure that equipment is maintained within design specifications.

The combustion turbine lube oil heat exchangers were removed, disassembled and inspected during the major inspection outages performed on each combustion turbine unit. GE did not identify any significant degradation of these heat exchangers in the Unit 1 outage final report. The Unit 2 lube oil heat exchangers were visually inspected during the current (October 2005) outage and were found to be in good condition with only minor pitting of carbon steel components, with no significant signs of corrosion or wall thinning in the copper alloy tubes. Pump casings, piping, and valve internal surfaces exposed to closed cooling water were also visually inspected during this outage with no significant corrosion or wall thinning observed.

Forked River combustion turbine power plant components in the scope of license renewal and exposed to closed cooling water, including head tanks, the water-to-air heat exchanger located at the mechanical draft cooling tower, and the various heat exchangers cooled by the closed cooling water system, have not experienced loss of intended function failures due to age-related degradation.

The combustion turbine operating experience provides objective evidence that the Forked River combustion turbine components subject to closed cooling water are not experiencing significant age-related degradation, and that the closed-cycle cooling water chemistry has been adequately maintained to effectively manage the effects of aging. This new closed cycle cooling water –

FRCT aging management program will include additional chemistry controls and components condition monitoring activities, providing further assurance that a non-corrosive environment is maintained such that aging-related degradation will continue to be minimized.

The project team reviewed the operating experience provided in the November 11, 2005, supplemental response to NRC RAI 2.5.1.19-1, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant's closed-cycle cooling water – FRCT program will adequately manage the aging effects that are identified in the applicant's FRCT AMRs for which this AMP is credited.

A7.3.0.3.2.2.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the Closed-Cycle Cooling Water System – FRCT program inthe November 11, 2005, supplemental response to NRC RAI 2.5.1.19-1, Appendix A, Section A.1.14A, which stated that the closed-cycle cooling water system aging management program is a new program that manages aging of piping, piping components, piping elements and heat exchangers that are included in the scope of license renewal for loss of material and cracking and are exposed to a closed cooling water environment at the Forked River combustion turbine power plant. The program relies on preventive measures to minimize corrosion by maintaining by maintaining water chemistry control parameters and by performing system monitoring and inspection activities to confirm that the aging effects are adequately managed. Chemistry control, performance monitoring, and inspection activities are based on industry-recognized guidelines of EPRI TR-107396, ?Closed Cooling Water Chemistry Guidelines," for closed-cycle cooling water systems.

In the supplemental response to NRC RAI 2.5.1.19-1, the applicant also stated that chemical control parameters will be monitored by annual water chemistry sampling. System operational monitoring activities will be performed at a frequency of at least once every six months. This new program will be implemented prior to entering the period of extended operation.

The project team also reviewed the applicant's license renewal commitment list in Appendix A of the supplemental response to RAI 2.5.1.19-1, and confirmed that the enhancements to this program are identified and will be implemented prior to the period of extended operation as item 52 of the commitments.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.14A and found that it was consistent with the GALL Report. The project team determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

A7.3.0.3.2.2.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report, are consistent with the GALL Report. In addition, the project team has reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. Also, the project team has reviewed the enhancement and determined that the implementation of the enhancement prior to the period of extended operation would result in the existing AMP being consistent with the GALL Report AMP to which it was compared. The project team also reviewed the UFSAR Supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

A7.3.0.3.2.3 Above Ground Steel Tanks – FRCT (B.1.21A)

In the applicant's response to NRC RAI 2.5.1.19-1 related to the OCGS LRA, dated November 11, 2005, Appendix D, Section B.1.12A, the applicant stated that OCGS AMP B.1.21A, "Aboveground Steel Tanks – FRCT," is a new plant program that is consistent with GALL AMP XI.M29, ?Aboveground Carbon Steel Tanks," with an exception.

A7.3.0.3.2.3.1 Program Description

In their response to RAI 2.5.1.19-1, the applicant stated that this program will provide for management of loss of material aging effects for outdoor carbon steel storage tanks. The tanks included in this program are the main fuel oil storage tank, the closed cooling water system head tanks located at the closed cooling water mechanical draft cooling towers, and the diesel starter jacket water (closed cooling water) head tanks located on the roof of the combustion turbine auxiliary enclosure. The program credits the application of paint coating as a corrosion preventive measure and includes periodic visual inspections to monitor degradation of the paint coating and any resulting metal degradation for the steel tanks.

Periodic internal UT inspections will be performed on the bottom of the outdoor steel Main Fuel Oil tank supported by earthen/concrete foundation. Other outdoor carbon steel tanks in the scope of this program are not directly supported by earthen or concrete foundations and therefore undergo external visual inspections without the necessity of bottom surface UT inspections.

The main fuel oil tank is the only in-scope outdoor tank supported by an earthen/concrete foundation. This tank does not have caulking or sealing around the tank-foundation interface. Raised tanks not directly supported by earthen or concrete foundations also do not have caulking or sealing. Therefore, inspection of sealant or caulking at the tank-foundation interface does not apply.

The Aboveground Steel Tanks – FRCT aging management program is a new program. External tank inspections will be at a frequency of every two years. Bottom surface UT inspections will be at a frequency of once every 20 years, based on plant specific operating experience with the Forked River Combustion Turbine power plant main fuel oil storage tank. This program, including the initial tank external paint inspections, will be implemented prior to the period of extended operation. The recommended UT inspection of the main fuel oil tank bottom was performed in October 2000, so it is not necessary to perform this initial inspection again prior to entering the period of extended operation. Based on the results of the October 2000 inspections, and subsequent repairs to the tank floor, the tank was certified to be suitable for the storage of number 2 fuel oil for a period of time not to exceed 20 years before the next internal inspection would be necessary. Therefore, UT inspections of the tank floor are not necessary prior to entering the period of extended operation, and will be performed again prior to October 2020.

A7.3.0.3.2.3.2 <u>Consistency with the GALL Report</u>

In their response to RAI 2.5.1.19-1, the applicant stated that the OCGS AMP B.1.21A is consistent with the GALL XI.M.29, with an exception.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.21A, including the program bases document PBD-AMP-B.1.21A, ?Aboveground Steel Tanks – FRCT," Revision 0, which provides an assessment of the AMP elements consistency with GALL AMP XI.M.29. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.21A and associated bases documents to determine consistency with GALL AMP XI.M29.

The project team reviewed those portions of the Aboveground Steel Tanks – FRCT program for which the applicant claims consistency with GALL AMP XI.M29 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's Aboveground Steel Tanks – FRCT program conforms to the recommended GALL AMP XI.M29, with the exception as described below.

A7.3.0.3.2.3.3 <u>Exceptions to the GALL Report</u>

The applicant stated, in the OCGS LRA, that the exception to the GALL Report program elements are as follows:

Elements:	7. Corrective Actions 8. Confirmation Process 9. Administrative Controls
Exception:	These elements are not accomplished in accordance with the AmerGen quality assurance (QA) program and are not in accordance with the requirements of 10 CFR Part 50, Appendix B.

The GALL Report identified the following recommendations for the above program elements associated with the exception taken.

> The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with 10 CFR Part 50, Appendix B. The staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

The applicant stated that in their response to RAI 2.5.1.19-1 that the Forked River Combustion Turbines and supporting systems are non-safety-related and are not subject to 10 CFR Part 50 Appendix B requirements in the current licensing basis (CLB). AmerGen has elected not to include this program under Oyster Creek 10 CFR Part 50 Appendix B Program. Instead, processes and procedures will be established to assure that conditions adverse to quality are promptly identified and corrected. Identified conditions that do not satisfy acceptance criteria will be documented, evaluated, and corrected as required to maintain the intended function of combustion turbines during the period of extended operation. In the case of significant conditions adverse to quality, the procedures will require that the cause of the condition be determined, actions to preclude repetition be taken, and the condition be reported to the appropriate level of management.

The confirmation process for the Forked River Combustion Turbine will focus on follow-up actions that must be taken to verify effective implementation of corrective actions and preclude repetition of significant conditions adverse to quality. The established process and procedures will include the requirements that measures be taken to preclude repetition of significant conditions adverse to quality. These measures will include actions to verify effective implementation of the proposed corrective actions, determination of root cause, tracking open corrective actions to completion, and reviews of corrective action effectiveness. In addition, the applicant stated that the Forked River Combustion Turbine procedures will include administrative controls that provide for formal review and approval of aging management activities.

The adequacy of the applicant's Quality Assurance Program associated with this program element is reviewed by DE staff and addressed in Section 3.0 of the SER related to the OCGS LRA. In their response to RAI 2.5.1.19-1, the applicant stated that it will meet the guidance in Branch Technical Position IQMB-1, ?Quality Assurance for Aging Management Programs." On this basis, the project team found this exception acceptable.

A7.3.0.3.2.3.4 Enhancements

None.

A7.3.0.3.2.3.5 Operating Experience

The applicant stated in their response to NRC RAI 2.5.1.19-1 that painting has provided adequate protection to the external surfaces of outdoor steel tanks, such that loss of material due to external corrosion has not been a concern. Some coating degradation has been observed, and the resulting exposed steel surfaces have experienced minor surface rusting that does not impact the tank intended function. Implementation of this new program, prior to the period of extended operation, will result in specific evaluations of any identified coating degradation, including an assessment on the potential impact on the tank intended function. These periodic inspections of tank coatings provide assurance that the intended functions will be maintained.

A certified tank inspection company inspected the main fuel oil tank on October 30, 2000. The inspection included ultrasonic testing (UT) of the floor, shell and roof, Magnetic Flux Leakage (MFL) testing of the floor with UT prove-up, level surveying of the foundation settlement and a thorough visual inspection of the entire tank structure.

The results of the MFL/UT inspection to detect floor underside corrosion indicate that some isolated underside corrosion is occurring. A total of eight MFL indications were found and evaluated, with the deepest underside corrosion pit measuring 0.185" remaining floor thickness. An analysis of corrosion rates since initial tank installation determined that a minimum 0.230" remaining floor thickness was required in order to certify the tank as acceptable until the next 20-year internal inspection. Four locations were identified below the required 0.230" thickness, and these locations were subsequently repaired with seal welded patch plates.

Visual inspection of the floor internal surface revealed 15 pits, with the deepest pit measuring 0.060" deep measured with a pit gauge. These pits were subsequently weld repaired.

Ultrasonic inspections at a number of locations on the shell and roof, coupled with a complete visual inspection of these areas, showed no signs of significant corrosion problems or structural deficiencies. There were no signs of service induced weld failures or leakage.

Early signs of paint failure were noted on the tank roof exterior surface.

The level survey indicated that the tank foundation is level within ¼".

The main fuel oil tank was found to be generally in good condition. With the repair of the identified floor corrosion, it was the professional opinion of the inspection firm that the tank is suitable for the storage of number 2 fuel oil for a period of time not to exceed 20 years before the next internal inspection will be necessary.

Unit 2 began a major outage inspection in October 2005. During the outage, with many components disassembled, components were visually inspected for signs of age related degradation. The external surfaces of the closed cooling water system head tanks located at the closed cooling water mechanical draft cooling towers, and the diesel starter jacket water (closed cooling water) head tanks located on the roof of the combustion turbine auxiliary enclosure, were visually inspected and did not show signs of significant paint degradation or metal corrosion. The main fuel oil storage tanks were walked down, including ascending the tank stairs up the side of the tank to the tank roof. The tank walls did not show signs of significant paint degradation or metal corrosion. The tank roof was observed to have early signs of coating failure, as was noted in the tank inspection report discussed above. The underlying metal showed minor surface rust. This condition does not threaten the structural integrity of the roof and continues to be monitored by routine site inspection.

The operating experience with the aboveground steel tanks at the Forked River Combustion Turbine power plant provides objective evidence that existing environmental conditions are not causing significant material degradation that could result in a loss of component intended functions. Recent external inspections confirm that the exterior paint has prevented significant material degradation. Internal inspections of the main fuel oil storage tank confirms that corrosion of the tank bottom is occurring at a rate that can be managed by the recommended future periodic inspections. Implementation of this new program will assure that the painted external tank surfaces are inspected at least once every two years, and that internal inspection of the main fuel oil storage tank will be performed at least once every 20 years, providing reasonable assurance that the aging effects will be adequately managed for the period of extended operation.

The project team reviewed the operating experience provided in the basis document, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant's Aboveground Steel Tanks program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

A7.3.0.3.2.3.6 <u>UFSAR Supplement</u>

The applicant provided its UFSAR Supplement for the Aboveground Steel Tanks – FRCT in their response to NRC RAI 2.5.1.19-1, which stated that the Aboveground Steel Tanks – FRCT aging management program is a new program that will manage corrosion of aboveground outdoor steel tanks. Paint coating is a corrosion preventive measure, and periodic visual inspections will monitor degradation of the paint coating and any resulting metal degradation of tank external surfaces. The aboveground tanks external surfaces will be visually inspected for coating degradation by walkdown at least once every two years. The main fuel oil storage tank is supported on a concrete foundation. This tank does not have caulking or sealing around the tank foundation interface. All other in-scope outdoor tanks are supported by structural steel. Therefore, inspection of sealant or caulking at the tank-foundation interface does not apply to the Aboveground Steel Tanks – FRCT aging management program.

The main fuel oil tank bottom is in contact with concrete and soil, and is inaccessible for visual inspection. Therefore, the program includes periodic non-destructive wall thickness examinations of the main fuel oil tank bottom to verify that significant corrosion is not occurring. This program, including the initial tank external paint inspections, will be implemented prior to the period of extended operation. The recommended UT inspection of the main fuel oil tank bottom was performed in October 2000, so it is not necessary to perform this inspection again prior to entering the period of extended operation. Based on the results of the October 2000 inspections, and subsequent repairs to the tank floor, the tank was certified to be suitable for the storage of number 2 fuel oil for a period of time not to exceed 20 years from October 2000, before the next internal inspection would be necessary. Therefore, additional UT inspections of the tank floor are not necessary prior to entering the period of extended operation and will be performed prior to October 2020.

The project team also reviewed the applicant’s updated license renewal commitment list in Appendix A of the supplemental response to RAI 2.5.1.19-1, and confirmed that this program is identified as a new program that will be implemented prior to the period of extended operation as item 53 of the commitments.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant’s Aboveground Steel Tanks – FRCT program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

The project team reviewed the UFSAR Supplement, found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR UFSAR Supplement table and as required by 10 CFR 54.21(d).

A7.3.0.3.2.3.7 Conclusion

On the basis of its audit and review of the applicant’s program, the project team found that those program elements for which the applicant claims consistency with the GALL Report, are consistent with the GALL Report. In addition, the project team has reviewed the exception and the associated justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. The project team also reviewed the UFSAR Supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

A7.3.0.3.2.4 Fuel Oil Chemistry – FRCT (AMP B.1.22A)

In the November 11, 2005, supplemental response to NRC RAI 2.5.1.19-1, Appendix D of the Enclosure, Section B.1.22A, the applicant stated that FRCT AMP B.1.22A, "Fuel Oil Chemistry –

FRCT," is a new plant program that is consistent with GALL AMP XI.M30, "Fuel Oil Chemistry," with exceptions.

A7.3.0.3.2.4.1 Program Description

In the November 11, 2005, supplemental response to NRC RAI 2.5.1.19-1, the applicant stated that the fuel oil chemistry-FRCT aging management program is a new program that provides assurance that contaminants are maintained at acceptable levels in new and stored fuel oil for systems and components within the scope of license renewal. The fuel oil storage tank will be maintained by monitoring and controlling fuel oil contaminants in accordance with the guidelines of the American Society for Testing Materials (ASTM). Fuel oil sampling activities will be in accordance with ASTM D 4057 for multilevel and tank bottom sampling. Fuel oil will be periodically sampled and analyzed for particulate contamination in accordance with modified ASTM Standard D 2276 Method A, or ASTM Standard D 6217, and for the presence of water and sediment in accordance with ASTM Standard D 2709 or ASTM Standard D 1796. The fuel oil storage tank will be periodically drained of accumulated water and sediment, and will be periodically drained, cleaned, and internally inspected. These activities effectively manage the effects of aging by providing reasonable assurance that potentially harmful contaminants are maintained at low concentrations.

A7.3.0.3.2.4.2 Consistency with the GALL Report

In the supplemental response to NRC RAI 2.5.1.19-1, the applicant stated that FRCT AMP B.1.22A is consistent with GALL AMP XI.M30, with exceptions.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for FRCT AMP B.1.22A, including the program basis document, PBD-AMP-B.1.22A, ?Fuel Oil Chemistry – FRCT," Revision 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M30. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in FRCT AMP B.1.22A to determine their consistency with GALL AMP XI.M30.

In reviewing this AMP, the project team noted that the ?detection of aging effects" program element description for AMP B.1.22A stated that based on the results of the October 2000 inspections and repairs, the Forked River fuel oil storage tank was certified to be suitable for the storage of number 2 fuel oil for a period of time not to exceed 20 years from October 2000, before the next internal inspection would be necessary. The project team asked the applicant to provide the technical basis for establishing the 20-year inspection interval.

In its response, the applicant stated that the Forked River fuel oil tank was inspected, repaired with a material allowance for corrosion, and certified for an additional 20 years of service before requiring internal re-inspection. The out-of-service inspection was consistent with the requirements of API-653 and NJAC 7:1E-2.2(a)4. The certification requires inservice inspections conducted at 5 year intervals, along with operation and maintenance consistent with industry standards.

The project team reviewed the applicant's response, as well as TAQ Inc. Tank certification dated October 30, 2000 for the FRCT fuel oil storage tank. The certification included an out-of-service inspection report, which showed that the FRCT fuel oil storage tank was in generally good condition. To maintain the certification for 20 years, inservice inspections are required every 5 years, which include the following:

- Visual inspection of roof and supports,
- External visual inspection for paint failures, pitting, and corrosion,
- Visual inspection of the floating roof for grooving, corrosion, pitting, and coating failures,
- Inspection of man-ways and nozzles, and
- Inspection of piping manifolds for leaks or damage

The certification also noted that the tank was constructed in 1989. The project team determined that the inservice inspections, together with the periodic draining of water and sediment from the tank would provide an acceptable means of controlling corrosion of the tank. In addition, the certification was in accordance with accepted industry standards, including API-653 and NJAC 7:1E-2.2(a)4. On this basis, the project team determined that the 20 year interval for internal inspections was acceptable.

The project team reviewed those portions of the FRCT fuel oil chemistry program for which the applicant claimed consistency with GALL AMP XI.M30 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's FRCT fuel oil chemistry program conforms to the recommended GALL AMP XI.M30,"Fuel Oil Chemistry," with the exceptions described below.

A7.3.0.3.2.4.3 Exceptions to the GALL Report

In the supplemental response to NRC RAI 2.5.1.19-1, the applicant stated the following exceptions to the GALL Report program elements:

Exception 1:

Elements:	2. Preventive Actions 3. Parameters Monitored or Inspected 4. Detection of Aging Effects
Exception:	Preventive Actions (Element 2), Parameters Monitored or Inspected (Element 3), and Detection of Aging Effects (Element 4) require that fuel oil tanks be periodically sampled, drained of accumulated water and sediment, cleaned, and internally inspected. Multilevel sampling and tank bottom sampling of the diesel starter engines fuel oil tanks is not performed. These tanks are supplied directly from the Fuel Oil Storage Tank, which will be periodically sampled and analyzed. The diesel starter engines fuel oil tanks are small in size and experience a high turnover rate of the fuel stored within as a result of routine engine operations. Stratification of fuel is not likely to occur due to the high turnover rate. Additionally, the diesel starter engines fuel oil tanks are skid mounted and enclosed within the combustion turbine accessories compartment, which is maintained at a constant temperature during cold periods through operation of enclosure heaters. Maintaining temperature during cold periods minimizes thermal cycling and reduces the potential for condensation formation within the tanks. The periodic draining of water and sediment from the

bottom of the diesel starter engines fuel oil tanks is therefore not required and the cleaning and internal inspection of the diesel starter engines fuel oil tanks is not necessary to verify degradation is not occurring due to the accumulation of particulate contamination and water and sediment

The GALL Report identifies the following recommendations for the ?preventive actions," ?parameters monitored or inspected," and ?detection of aging effects" program elements associated with the exception taken:

> 2. *Preventive Actions:* The quality of fuel oil is maintained by additions of biocides to minimize biological activity, stabilizers to prevent biological breakdown of the diesel fuel, and corrosion inhibitors to mitigate corrosion. Periodic cleaning of a tank allows removal of sediments, and periodic draining of water collected at the bottom of a tank minimizes the amount of water and the length of contact time. Accordingly, these measures are effective in mitigating corrosion inside diesel fuel oil tanks. Coatings, if used, prevent or mitigate corrosion by protecting the internal surfaces of the tank from contact with water and microbiological organisms.
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> 3. *Parameters Monitored or Inspected:* The AMP monitors fuel oil quality and the levels of water and microbiological organisms in the fuel oil, which cause the loss of material of the tank internal surfaces. The ASTM Standard D 4057 is used for guidance on oil sampling. The ASTM Standards D 1796 and D 2709 are used for determination of water and sediment contamination in diesel fuel. For determination of particulates, modified ASTM D 2276, Method A, is used. The modification consists of using a filter with a pore size of 3.0 mm, instead of 0.8 mm. These are the principal parameters relevant to tank structural integrity.
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> 4. *Detection of Aging Effects:* Degradation of the diesel fuel oil tank cannot occur without exposure of the tank internal surfaces to contaminants in the fuel oil, such as water and microbiological organisms. Compliance with diesel fuel oil standards in item 3, above, and periodic multilevel sampling provide assurance that fuel oil contaminants are below unacceptable levels. Internal surfaces of tanks that are drained for cleaning are visually inspected to detect potential degradation. However, corrosion may occur at locations in which contaminants may accumulate, such as a tank bottom, and an ultrasonic thickness measurement of the tank bottom surface ensures that significant degradation is not occurring.

As part of the justification for this exception, the project team noted that the FRCT license renewal document stated that the diesel starter engines' fuel oil tanks are small in size and experience a high turnover rate of the fuel stored within as a result of routine engine operations, and that stratification of the fuel is not likely to occur due to this high turnover rate. The applicant was asked to provide additional information as to a) whether the tanks have the capability to be inspected, b) what the day tank fuel turnover rate is, and the basis for concluding that stratification would not occur, and c) the operating experience with water and sediment buildup in the FRCT fuel storage tank.

In its response, the applicant stated that the diesel starter engines' fuel oil tanks are small tanks built into each of the combustion turbine accessory skids. These tanks do not have the capability for multilevel or tank bottom sampling without disassembling tank piping connections. In addition, the FRCT units are commercially operated units that are used to supply peak power to the grid. As such, they are frequently started and stopped, requiring frequent starting and running of the starting diesel engine. The diesel engine runs for approximately 20 minutes each time the associated turbine is started. The tank level is checked regularly during operator rounds, and the tanks are filled manually from the turbine oil header, when required. The tanks require filling approximately once every month on average; more frequently during high usage months and less frequently during low usage months depending on seasonal grid load. Since the diesel engines are routinely operated, the fuel tanks are regularly drawn down and periodically refilled precluding fuel stratification. The enclosure where the tank is located is maintained at a constant temperature during cold periods by operation of enclosure heaters.

The applicant also stated that the fuel oil storage tank that supplies the diesel engine starter fuel tanks was drained and an internal inspection was performed in October 2000. No evidence of water accumulation was found in the tank. The tank floor includes a sump pit designed to collect any water. The sump pit was found to be in good condition, with no visible corrosion, indicating that the tank has not experienced significant water accumulation or sediment buildup. Over the entire surface of the floor, 15 corrosion pits were found, with the deepest pit measuring 0.060" deep, as measured with a pit gauge. These pits were subsequently weld repaired. In addition, the tank design includes a floating roof that precludes atmospheric moisture intrusion into the oil. Water was never drained from the tank bottom prior to the tank inspection. Since the internal inspection did not reveal significant water accumulation, there is no need to periodically drain the tank bottom.

The applicant also stated in its response that one-time inspections will be performed on a number of components in the fuel oil supply system, to confirm the effectiveness of the Fuel Oil Chemistry – FRCT aging management program. An effective fuel oil chemistry program will preclude aging degradation of the diesel engine supply tanks without the need to disassemble and inspect the tanks. If the results of one-time inspections indicate that fuel oil chemistry controls have been ineffective, corrective actions will be implemented, including evaluation and/or inspection of additional system components potentially affected, including the diesel fuel tanks.

The project team reviewed the applicant’s response and determined that the turnover rate for the FRCT diesel starter engine tanks is reasonable, and will prevent stratification of the fuel stored in these tanks. Further, the enclosed location of the FRCT diesel starter engine tanks together with the use of the enclosure heaters to minimize thermal cycling of these tanks will reduce the potential for condensation forming inside the tanks. Based on the operating experience with the FRCT fuel oil storage tank, moisture intrusion has not been a problem. If corrosion due to moisture intrusion were to occur, the one-time inspections of the FRCT system components would provide adequate detection in a timely manner. On this basis, the project team determined that this exception is acceptable.

<u>Exception 2</u>

Elements:	1. Scope of Program 5. Monitoring and Trending
Exception:	The Program Description, Scope of Program (Element 1), and Monitoring and Trending (Element 5) refer to plant technical specifications related to fuel oil quality. There are no plant technical specifications at the Forked River Combustion Turbine power plant.

The GALL Report identifies the following recommendations for the ?scope of program," and ?monitoring and trending" program elements associated with the exception taken:

> 1. *Scope of Program:* The program is focused on managing the conditions that cause general, pitting, and microbiologically influenced (MIC) of the diesel fuel tank internal surfaces in accordance with the plant's technical specifications (i.e., NUREG- 1430, NUREG-1431, NUREG-1432, NUREG-1433) on fuel oil purity and the guidelines of ASTM Standards D1796, D2276, D2709, D6217, and D4057. The program serves to reduce the potential of exposure of the tank internal surface to fuel oil contaminated with water and microbiological organisms.
>
> 5. *Monitoring and Trending:* Water and biological activity or particulate contamination concentrations are monitored and trended in accordance with the plant's technical specifications or at least quarterly. Based on industry operating experience, quarterly sampling and analysis of fuel oil provides for timely detection of conditions conducive to corrosion of the internal surface of the diesel fuel oil tank before the potential loss of its intended function.

As discussed above, the project team asked the applicant to provide additional information on the specifications that would be used to determine if the fuel oil sampling results are acceptable.

In its response, the applicant stated that water and sediment concentrations are tested in accordance with ASTM Standards D 1796 or D 2709. Particulate contamination is determined by the use of modified ASTM Standard D 2276, method A, or ASTM Standard D 6217. Acceptance criteria are per ASTM D 975. Use of ASTM D 975 is consistent with General Electric specification GEI-41047H for the FRCT.

The project team reviewed the applicants response and determined that the specifications to be used to establish acceptance criteria for the fuel oil samples are based on ASTM Standard D 975, with is consistent with General Electric specification GEI-41047H for the FRCT, as well as the specifications referenced in Regulatory Guide 1.137. On this basis, the project team determined that this exception is acceptable.

<u>Exception 3</u>

Elements:	7. Corrective Actions 8. Confirmation Process 9. Administrative Controls
Exception:	These elements are not accomplished in accordance with the AmerGen quality assurance (QA) program and are not in accordance with the requirements of 10 CFR Part 50, Appendix B.

The GALL Report identified the following recommendations for the above program elements associated with the exception taken:

> The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with 10 CFR Part 50, Appendix B. The staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

The adequacy of the applicant's Quality Assurance Program associated with this program element is reviewed by DE staff and addressed in Section 3.0 of the SER related to the OCGS LRA. In their response to RAI 2.5.1.19-1, the applicant stated that it will meet the guidance in Branch Technical Position IQMB-1, ?Quality Assurance for Aging Management Programs." On this basis, the project team found this exception acceptable.

A7.3.0.3.2.4.4 Enhancements

None.

A7.3.0.3.2.4.5 Operating Experience

In the November 11, 2005, supplemental response to NRC RAI 2.5.1.19-1, Section B.1.22A, the applicant stated that fuel oil chemistry activities have been proven to be effective in managing the aging effects associated with fuel oil systems so that the intended functions of components within the scope of license renewal will be maintained during the period of extended operation. On October 30, 2000, to satisfy the recommendations of the American Petroleum Institute's (API's) Standard No. 653 entitled ?Tank Inspection, Repair, Alteration, and Reconstruction," TAQ, Inc. performed an ?out-of-service" inspection of the Forked River Combustion Turbine fuel oil storage tank. The inspection included ultrasonic testing (UT) and visual (VT) inspection of the floor. The inspection was performed by an API-653 Certified Tank Inspector after 10 years of service (date of original tank's construction was 1989). The following summary is provided concerning tank floor inspections: VT inspection of the floor revealed 15 ?product side" pits with the deepest pit measuring 0.060" deep (measured by pit gauge). The pitting was weld repaired. The floor is equipped with a 24" sump serviced by a 4" water draw-off line. There was no topside corrosion noted on the sumps floor and walls and UT inspection to detect underside corrosion revealed no appreciable corrosion.

Based on the above findings, it was the professional opinion of the qualified inspector that the Forked River fuel oil storage tank will be suitable for the storage of No. 2 fuel oil for a period of time not to exceed 20 years before the next internal inspection. In October 2001 (Unit 2 FRCT) and March 2004 (Unit 1 FRCT), GE Energy Services performed major inspection and maintenance activities, and documented all work performed in inspection reports dated January 4, 2002, and June 7, 2004, respectively. The equipment inspections included the turbine and its internals and support equipment. All work was carried out closely following the instructions and guidance found in the original equipment manufacturer's design, maintenance and inspection manuals. Acceptance criteria and corrective actions for these activities ensure that equipment is maintained within design specifications.

The project team reviewed the operating experience provided for the FRCT fuel oil system, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience, and discussions with the applicant's technical staff, the project team determined that the applicant's fuel oil chemistry program – FRCT will adequately manage the aging effects that are identified in the FRCT AMRs for which this AMP is credited.

A7.3.0.3.2.4.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the Fuel Oil Chemistry – FRCT aging management program in the November 11, 2005, supplemental response to NRC RAI 2.5.1.19-1, Appendix D, Section A.1.22A, which states that the fuel oil chemistry-FRCT aging management program is a new program that provides assurance that contaminants are maintained at acceptable levels in new and stored fuel oil for systems and components within the scope of License Renewal. The fuel oil storage tank will be maintained by monitoring and controlling fuel oil contaminants in accordance with the guidelines of the American Society for Testing Materials (ASTM). Fuel oil sampling activities will be in accordance with ASTM D 4057 for multilevel and tank bottom sampling. Fuel oil will be periodically sampled and analyzed for particulate contamination in accordance with modified ASTM Standard D 2276, method A, or ASTM Standard D 6217, and for the presence of water and sediment in accordance with ASTM Standard D 2709 or ASTM Standard D 1796. The fuel oil storage tank will be periodically drained of accumulated water and sediment, and will be periodically drained, cleaned, and internally inspected. These activities effectively manage the effects of aging by providing reasonable assurance that potentially harmful contaminants are maintained at low concentrations. This new program will be implemented prior to entering the period of extended operation.

The applicant further stated in its UFSAR supplement for AMP B.1.22A that the internal inspection of the main fuel oil tank was performed in October 2000, so it is not necessary to perform this inspection again prior to entering the period of extended operation. Based on the results of the October 2000 inspections and repairs, the tank was certified to be suitable for the storage of number 2 fuel oil for a period of time not to exceed 20 years from October 2000, before the next internal inspection would be necessary. Therefore, additional internal inspections of the tank floor are not necessary prior to entering the period of extended operation and will be performed prior to October 2020.

The project team also reviewed the applicant's updated license renewal commitment list in Appendix A of the supplemental response to RAI 2.5.1.19-1, and confirmed that this program is identified as a new program that will be implemented prior to the period of extended operation as item 54 of the commitments.

The project team reviewed the UFSAR Supplement for FRCT AMP B.1.22A, found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

A7.3.0.3.2.4.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report are consistent with the GALL Report. In addition, the project team reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. The project team also reviewed the UFSAR Supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

A7.3.0.3.2.5 One-Time Inspection – FRCT (B.1.24A)

In the November 11, 2005, supplemental response to NRC RAI 2.5.1.19-1, Appendix D, Section B.1.24A, the applicant stated that FRCT AMP B.1.24A, "One-Time Inspection – FRCT," is a new plant program that will be consistent with GALL AMP XI.M32, "One-Time Inspection."

A7.3.0.3.2.5.1 Program Description

In the November 11, 2005, supplemental response to NRC RAI 2.5.1.19-1, the applicant stated that the one-time inspection-FRCT aging management program is a new program that will provide reasonable assurance that the loss of material and loss of heat transfer aging effects are not occurring, or that the aging effects are occurring slowly enough to not affect the fuel oil and lubricating oil system components intended functions during the period of extended operation, and therefore will not require additional aging management. The program is credited for components in fuel oil and lubricating oil environments where either (a) an aging effect is not expected to occur but there is insufficient data to completely rule it out, (b) an aging effect is expected to progress very slowly in the specified environment, but the local environment may be more adverse than that generally expected, or (c) the characteristics of the aging effect include a long incubation period.

The applicant further stated that the One-Time Inspection – FRCT will be used only to provide assurance that loss of material and loss of heat transfer for components subject to FRCT fuel oil and lubricating oil environments are not occurring, or that the aging effects are insignificant. It will not be used to confirm that aging is not occurring or insignificant in other FRCT environments.

The applicant further stated that the One-Time Inspection – FRCT will be used to verify that the fuel oil and lubricating oil systems activities are effective in preventing or minimizing aging to the extent that it will not cause the loss of intended function during the period of extended operation. The program will require inspection at locations of low or stagnant flow, which are susceptible to water pooling and gradual accumulation or concentration of agents that promote loss of material and loss of heat transfer. The program will provide inspections that either verify that unacceptable loss of material or loss of heat transfer are not occurring, or initiate additional actions that will assure the intended function of affected components will be maintained during the period of extended operation. The new program elements include (a) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience; (b) identification of the inspection locations in the system or component based on the aging effect; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined; and (d) evaluation of the need for follow-up examinations to monitor the progression of aging if age related degradation is found that could jeopardize an intended function before the end of the period of extended operation. When evidence of an aging effect is revealed by a one-time inspection, an evaluation of the inspection results will be perform to identify appropriate corrective actions.

The applicant further stated that the inspection sample includes ?worse case" one-time inspection of more susceptible materials in the fuel oil and the lubricating oil environments (e.g., low or stagnant flow areas) to manage the effects of aging. Examination methods will include visual examination and/or volumetric examinations. Acceptance criteria are based on the design codes and standards for the Forked River combustion turbines and manufacturer's recommendations. The one-time inspection-FRCT aging management program will be implemented prior to the period of extended operation.

A7.3.0.3.2.5.2 Consistency with the GALL Report

In the supplemental response to NRC RAI 2.5.1.19-1, the applicant stated that FRCT AMP B.1.24A is consistent with GALL AMP XI.M32, with exceptions.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for FRCT AMP B.1.24A, including the program basis document, PBD-AMP-B.1.24A, ?One-Time Inspection – FRCT", Revision 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M32. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in FRCT AMP B.1.24A and associated bases documents to determine their consistency with GALL AMP XI.M32.

In reviewing this AMP, the project team noted in the FRCT license renewal document program description for AMP B.1.24A that the description of the ?parameters monitored or inspected" AMP element stated that inspection methods consist of nondestructive examination, including visual, volumetric, and surface techniques. Since FRCT AMP B.1.24A is not based on the requirements of the ASME Code, as stated in the first exception for this AMP, the applicant was to describe the rational to be used in selecting the inspection method for the various types of components in the scope of this AMP.

In its response, the applicant stated that this aging management program performs one-time inspections to confirm the effectiveness of the Fuel Oil Chemistry – FRCT and Lubricating Oil Analysis – FRCT programs. The inspection methods selected will depend on the component type, intended function, material and aging effect. Heat transfer surfaces of components with a heat transfer intended function will be inspected using visual inspection to identify fouling or other surface degradation that could impair the heat transfer function. This same visual inspection also assures that the pressure boundary intended function is maintained. The stainless steel filter element with a filter intended function will also be inspected using visual techniques to identify accumulations of dirt or sediment, or degradation of the filter element that could impair or reduce the effectiveness of the filter intended function. Similarly, restricting orifices will be inspected using visual techniques to identify degradation of the orifice that could impair or reduce the effectiveness of the throttle intended function. This same visual inspection also assures that the pressure boundary intended function is maintained.

The applicant further stated that remaining mechanical components in the scope of this program have a pressure boundary intended function and are subject to loss of material aging effect. Mechanical components will be inspected using visual or ultrasonic techniques in order to determine the extent of loss of material by evaluating the extent of loss of wall thickness. The technique selected will depend on the component type, and whether the inspection involves disassembly or is performed without disassembly. For combustion turbine components, the most appropriate technique will be determined based on manufacturer's experience and recommendations for the component. Piping can be inspected for wall thickness using ultrasonic techniques. Visual inspection techniques are appropriate for pump casings, strainer bodies, filter housings, and valve bodies when disassembled during maintenance activities. The above described component inspections will confirm the effectiveness of the Fuel Oil Chemistry – FRCT and Lubricating Oil Analysis – FRCT aging management programs.

The project team reviewed the applicant's response, which provides the rational to be used in selecting the appropriate inspection technique. Heat transfer surfaces of components with a heat transfer intended function will be inspected using visual inspection to identify fouling or other surface degradation that could impair the heat transfer function. Visual inspection will also be used to assure that the pressure boundary intended function is maintained. The stainless steel filter element with a filter intended function will also be inspected using visual techniques to identify accumulations of dirt or sediment, or degradation of the filter element that could impair or reduce the effectiveness of the filter intended function. Similarly, restricting orifices will be inspected using visual techniques to identify degradation of the orifice that could impair or reduce the effectiveness of the throttle intended function. The remaining mechanical components in the scope of this program have a pressure boundary intended function and are subject to loss of material aging effect. Mechanical components will be inspected using visual or ultrasonic techniques in order to determine the extent of loss of material by evaluating the extent of loss of wall thickness. These inspection techniques are reasonable for inspecting the fuel oil system and the lubricating oil system for the Forked River combustion turbines and will provide reasonable assurance that the aging effects for which this program is credited will be managed. On this basis, the project team determined that the applicant's rational for selecting inspection techniques was acceptable.

Upon further review of this AMP, the project team noted in the FRCT license renewal document description for AMP B.1.24A that the ?detection of aging effects" AMP element discusses sample selection; however, the rational for selecting the sample population was not provided. The applicant was asked to provide additional information on how the sample population for the one-time inspection will be determined.

In its response, the applicant stated that the component sample inspection requirements for the Forked River combustion turbine components will be determined based on an evaluation of operating experience with these units and similar General Electric combustion turbine units that have been in service for many years. The manufacturer and power industry users have developed maintenance and inspection plans designed to attain high operational reliability over time. The most appropriate sample size and inspection locations will be determined based on this experience and manufacturer's recommendations. Since a considerable amount of operating experience is available for combustion turbines, the project team determined that the use of operating experience is an acceptable means of assuring that an appropriate sample population will be obtained. On this basis, the project team determined that the applicant's response was acceptable.

The project team reviewed those portions of the applicant's One-Time Inspection Program – FRCT for which the applicant claims consistency with GALL AMP XI.M32 and found that they are consistent with this GALL Report AMP. The project team found that the applicant's One-Time Inspection – FRCT program conforms to the recommended GALL AMP XI.M32, ?One-Time Inspection," with the exceptions described below.

A7.3.0.3.2.5.3 <u>Exceptions to the GALL Report</u>

In the supplemental response to NRC RAI 2.5.1.19-1, the applicant stated the following exceptions to the GALL Report program:

<u>Exception 1</u>

Elements: 3. Parameters Monitored or Inspected
4. Detection of Aging Effects

Exception: Parameters Monitored or Inspected (Element 3) and Detection of Aging Effects (Element 4) require that inspections be performed by qualified personnel following procedures consistent with the requirements of ASME Code and 10 CFR Part 50, Appendix B. The Forked River Combustion Turbine fuel oil and lubricating oil systems are not designed to ASME requirements and are not safety-related. Thus, ASME requirements are not applicable and AmerGen has elected not to include the One-Time Inspection – FRCT under 10 CFR Part 50 Appendix B requirements. Personnel qualified to industry standards using approved procedures consistent with the combustion turbine manufacturer's recommendations will perform the inspections. The One-Time Inspection – FRCT will be conducted under a separate quality assurance activity specifically developed for Forked River Combustion Turbines as discussed in the Corrective Actions, Confirmation Process, and Administrative Controls elements.

The GALL Report identifies the following recommendations for the ?parameters monitored/ inspected" and ?detection of aging effects program elements associated with the exception taken:

3. *Parameters Monitored or Inspected*: The program monitors parameters directly related to the degradation of a component. Inspection is to be performed by qualified personnel following procedures consistent with the requirements of the ASME Code and 10 CFR Part 50, Appendix B, using a variety of NDE methods, including visual, volumetric, and surface techniques.

4. *Detection of Aging Effects*: The inspection includes a representative sample of the system population, and, where practical, focuses on the bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin. The program will rely on established NDE techniques, including visual, ultrasonic, and surface techniques that are performed by qualified personnel following procedures consistent with the ASME Code and 10 CFR Part 50, Appendix B. The inspection and test techniques will have a demonstrated history of effectiveness in detecting the aging effect of concern.

The project team reviewed this exception and noted that the applicant will use personnel qualified to industry standards using approved procedures consistent with the combustion turbine manufacturer's recommendations to perform the inspections. The project team determined that the use of personnel qualified to industry standards using approved procedures consistent with the combustion turbine manufacturer's recommendations will provide adequate assurance that the inspections will be performed by qualified personnel. On this basis, the project team determined that this exception is acceptable.

Exception 2

Elements:	7. Corrective Actions 8. Confirmation Process 9. Administrative Controls
Exception:	These elements are not accomplished in accordance with the AmerGen quality assurance (QA) program and are not in accordance with the requirements of 10 CFR Part 50, Appendix B.

The GALL Report identified the following recommendations for the above program elements associated with the exception taken:

> The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with 10 CFR Part 50, Appendix B. The staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

The adequacy of the applicant‘s Quality Assurance Program associated with this program element is reviewed by DE staff and addressed in Section 3.0 of the SER related to the OCGS LRA. In their response to RAI 2.5.1.19-1, the applicant stated that it will meet the guidance in Branch Technical Position IQMB-1, ?Quality Assurance for Aging Management Programs.” On this basis, the project team found this exception acceptable.

A7.3.0.3.2.5.4 Enhancements

None

A7.3.0.3.2.5.5 Operating Experience

In the November 11, 2005, supplemental response to NRC RAI 2.5.1.19-1, the applicant stated that in October 2001 (Unit 2 FRCT) and March 2004 (Unit 1 FRCT), GE Energy Services performed major inspection and maintenance activities, and documented all work performed in inspection reports dated January 4, 2002, and June 7, 2004, respectively. The equipment inspections included the turbine and its internals, and support equipment. All work was carried out closely following the instructions and guidance found in the original equipment manufacturer’s design, maintenance and inspection manuals. Acceptance criteria and corrective actions for these activities ensure that equipment is maintained within design specifications.

The applicant further stated that the Unit 1 inspection was a major maintenance inspection. This was the first major inspection that was performed on the unit since initial installation in 1988. During the Unit 1 inspection, the fuel forwarding pumps and emergency DC lube oil pumps were removed and sent to the General Electric service shop for cleaning, inspection and repairs. The GE report does not indicate any issues associated with degradation of these pump casings. The combustion turbine lube oil system was drained, cleaned and inspected. Various pumps were inspected, and the lube oil coolers were cleaned. No degradation of these components was identified. The main lube oil pump was disassembled and inspected, and no defects were observed.

The applicant further stated that the Unit 2 inspection was a fuel nozzle and combustion section inspection. The lube oil filters were replaced. The inspection included a borescope and combustion inspection, removal of exhaust frame cooling piping, and disconnection of the fuel lines for inspection, and fuel nozzle inspection, repair, and testing. The GE report does not identify any issues with the disassembled fuel oil piping. Unit 2 began a major outage inspection in October 2005. During the outage, with many components disassembled, components were visually inspected for signs of age related degradation. The internal surfaces of disassembled stainless steel piping and flexible hoses were observed, and there were no signs of corrosion or wall thinning. The combustion turbine lube oil heat exchangers were dissembled, cleaned and inspected. The carbon steel and copper alloy heat exchanger components normally exposed to lubricating oil were found to be in excellent condition. The standby heat exchanger that is not normally in service was found to have some minor accumulation of sediment that was cleaned off. Carbon steel pump casings that are normally submerged in the lubricating oil reservoir were visually observed to be in excellent condition, with no signs of corrosion. The carbon steel internal surfaces of the lubricating oil reservoir were also observed to be in excellent condition, with no signs of corrosion.

The project team reviewed the operating experience provided for the FRCT to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience, and discussions with the applicant's technical staff, the project team determined that the applicant's One-Time Inspection – FRCT program will adequately manage the aging effects that are identified in the FRCT AMRs for which this AMP is credited.

A7.3.0.3.2.5.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the One-Time Inspection – FRCT program in the November 11, 2005, supplemental response to NRC RAI 2.5.1.19-1, Appendix D, Section A.1.24A, which stated that the One-Time Inspection – FRCT aging management program is a new program that will provide a means of confirming the aging effects of loss of material and loss of heat transfer are either not occurring or are progressing so slowly as to not have an effect on the intended function of the combustion turbine fuel oil and lubricating oil system components within the period of extended operation. Additionally, this program will address potentially long incubation periods for loss of material and loss of heat transfer aging effects.

The applicant's UFSAR further stated that the One-Time Inspection – FRCT program will provide measures to verify that an aging management program is not needed, confirm the effectiveness of existing activities, or determine that degradation is occurring which will require evaluation and corrective action. The program will be implemented prior to the period of extended operation.

The applicant's UFSAR further stated that inspection methods will include visual examination or volumetric examinations. Inspections will be performed by qualified personnel using procedures developed consistent with the quality classification of the Forked River combustion turbines. Acceptance criteria will be in accordance with design standards for the combustion turbines and manufacturer's recommendations. The One-Time Inspection – FRCT program provides for the evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could jeopardize an intended function before the end of the period of extended operation. Should aging effects be detected, the program will initiate actions to characterize the nature and extent of the aging effect and determine what subsequent monitoring is needed to ensure intended functions are maintained during the period of extended operation.

The project team also reviewed the applicant's updated license renewal commitment list in Appendix A of the supplemental response to RAI 2.5.1.19-1, and confirmed that this program is identified as a new program that will be implemented prior to the period of extended operation as item 55 of the commitments.

The project team reviewed the UFSAR Supplement for FRCT AMP B.1.24A, found that it was consistent with the GALL Report, and determined that it provided an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

A7.3.0.3.2.5.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report are consistent with the GALL Report. In addition, the project team reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. The project team also reviewed the UFSAR Supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

A7.3.0.3.2.6 Selective Leaching of Materials – FRCT (B.1.25A)

In the applicant's response to NRC RAI 2.5.1.19-1 related to the OCGS LRA, dated November 11, 2005, Appendix D, Section B.1.25A, the applicant stated that OCGS AMP B.1.25A," Selective Leaching of Materials – FRCT," aging management program is a new program that is consistent with GALL AMP XI.M33, ?Selective Leaching of Materials," with exceptions.

A7.3.0.3.2.6.1 Program Description

In their response to RAI 2.5.1.19-1, the applicant stated that this program will ensure the integrity of the components that may be susceptible to selective leaching at the Forked River Combustion Turbine power plant. The AMP includes a one-time visual inspection and hardness measurement of selected components to determine whether loss of materials due to selective leaching is occurring, and whether the process will affect the ability of the components to perform their intended function for the period of extended operation. The One-Time Inspection Program includes visual inspections, hardness tests and other appropriate examination methods as may be required to confirm or rule out selective leaching, and to evaluate the remaining component wall thickness when leaching is identified. Components of the susceptible materials at the FRCT site are comprised of copper alloy materials exposed to a treated water (closed cooling water (CCW)) environment. The purpose of the program is to determine if loss of material due to selective leaching of the zinc component of the alloy (dezincification) is occurring. If selective leaching is found, the program provides for evaluation as to the effect it will have on the ability of the affected components ability to perform their intended function for the period of extended operation.

The Selective Leaching of Materials – FRCT aging management program is a new program. This new program will be implemented in the final 10 years of the period of extended operation.

A7.3.0.3.2.6.2 Consistency with the GALL Report

In their response to RAI 2.5.1.19-1, the applicant stated that the OCGS AMP B.1.25A is consistent with the GALL XI.M.33, with an exception.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.25A, including the program bases document PBD-AMP-B.1.25A, ?Selective Leaching of Materials – FRCT," Revision 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M33. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.25A and associated bases documents to determine consistency with GALL AMP XI.M33.

The project team reviewed those portions of the Selective Leaching of Materials – FRCT program for which the applicant claims consistency with GALL AMP XI.M18 and found that they are consistent with the GALL Report AMP. The project team found that the applicant's Selective Leaching of Materials – FRCT program conforms to the recommended GALL AMP XI.M33, with the exception as described below.

A7.3.0.3.2.6.3 Exceptions to the GALL Report

The applicant stated in their response to RAI 2.5.1.19-1 the following exception to the GALL Report program elements:

Exception

Elements:	7. Corrective Actions 8. Confirmation Process 9. Administrative Controls
Exception:	These elements are not accomplished in accordance with the AmerGen quality assurance (QA) program and are not in accordance with the requirements of 10 CFR Part 50, Appendix B.

The GALL Report identified the following recommendations for the above program elements associated with the exception taken.

> The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with 10 CFR Part 50, Appendix B. The staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

The adequacy of the applicant's Quality Assurance Program associated with this program element is reviewed by DE staff and addressed in Section 3.0 of the SER related to the OCGS LRA. In their response to RAI 2.5.1.19-1, the applicant stated that it will meet the guidance in Branch Technical Position IQMB-1, ?Quality Assurance for Aging Management Programs." On this basis, the project team found this exception acceptable.

A7.3.0.3.2.6.4 Enhancements

None.

A7.3.0.3.2.6.5 Operating Experience

The applicant stated in their response to NRC RAI 2.5.1.19-1 that selective leaching 'one-time' inspection process is consistent with staff guidance in the inspection techniques utilized and the selection of components inspected.

Selective leaching has not been identified at the Forked River Combustion Turbine power plant. In March 2004 (Unit 1 FRCT), GE Energy Services performed major inspection and maintenance activities and documented all work performed in an inspection report dated June 7, 2004. All work was carried out closely following the instructions and guidance found in the original equipment manufacturer's design, maintenance and inspection manuals. Acceptance criteria and corrective actions for these activities ensure that equipment is maintained within design specifications.

The Unit 1 inspection was a major maintenance inspection. This was the first major inspection that was performed on the unit since initial installation in 1988. During the Unit 1 inspection the combustion turbine lubricating oil system was drained, cleaned and inspected. The equipment inspections included the lube oil coolers subject to the closed cooling water environment. The coolers were removed from the sump, cleaned and inspected. No degradation of these components was identified. Unit 2 began a major outage inspection in October 2005. The combustion turbine lubricating oil heat exchangers were dissembled, cleaned and inspected. Based on visual observations, the copper alloy heat exchanger components normally exposed to closed cooling water appeared to be in excellent condition. The tube ends at the tube sheet did not show signs of significant wall thinning. The operating experience with the combustion turbine system heat exchangers subject to a closed cooling water environment and potentially subject to selective leaching, demonstrates that selective leaching has not been an identified concern. This operating experience demonstrates that either the FRCT closed cooling water environment is less conducive to selective leaching, or that selective leaching is occurring slowly enough as to not yet become evident. Because selective leaching is a slow acting corrosion process, this program will include inspections for selective leaching within the final 10 years of the period of extended operation.

The project team reviewed the operating experience provided in the basis document, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant's Selective Leaching of Materials – FRCT program will adequately manage the aging effects/mechanism that are identified in the OCGS LRA for which this AMP is credited.

A7.3.0.3.2.6.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the selective leaching materials – FRCT program in their response to NRC RAI 2.5.1.19-1 which stated that the aging management program is a new program that will consist of inspections of components constructed of susceptible materials to determine if loss of material due to selective leaching is occurring. For the FRCT power plant, these are limited to copper alloy materials exposed to a closed cooling water environment. One-time inspections will consist of visual inspections supplemented by hardness tests. If selective leaching is found, the condition will be evaluated to determine the ability of the component to perform its intended function until the end of the period of extended operation and for the need to expand inspections. This new program will be implemented in the time period after January 2018 and prior to January 2028.

The project team also reviewed the applicant's updated license renewal commitment list in Appendix A of the supplemental response to RAI 2.5.1.19-1, and confirmed that this program is identified as a new program that will be implemented prior to the period of extended operation as item 56 of the commitments.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant's Selective Leaching Materials – FRCT program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.25A found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

A7.3.0.3.2.6.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report, are consistent with the GALL Report. In addition, the project team has reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. The project team also reviewed the UFSAR Supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

A7.3.0.3.2.7 Buried Piping Inspection – FRCT (B.1.26A)

In the applicant's response to NRC RAI 2.5.1.19-1 related to the OCGS LRA, dated November 11, 2005, Appendix D, Section B.1.26A, the applicant stated that AMP B.1.26A, "Buried Pipe Inspection – FRCT," is consistent with GALL AMP XI.M34, ?Buried Piping and Tanks," with an exception.

A7.3.0.3.2.7.1 Program Description

In their response to RAI 2.5.1.19-1, the applicant stated that the Buried Piping Inspection – FRCT aging management program is a new aging management program and includes preventive measures to mitigate corrosion and periodic inspection of external surfaces for loss of material to manage the effects of corrosion on the pressure-retaining capacity of carbon steel piping in a soil (external) environment. Preventive measures are in accordance with standard industry practices for maintaining external coatings and wrappings. External inspections of buried piping will occur opportunistically when excavated during maintenance. Within10 years prior to entering the period of extended operation, inspection of buried piping will be performed unless an opportunistic inspection occurs within this ten-year period. Upon entering the period of extended operation, inspection of buried piping will again be performed within the next ten years, unless an opportunistic inspection occurs during this ten-year period.

A7.3.0.3.2.7.2 Consistency with the GALL Report

In their response to RAI 2.5.1.19-1, the applicant stated that the OCGS AMP B.1.26A is consistent with the GALL AMP XI.M34, with an exception.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.26A, including the program bases document PBD-AMP-B.1.26A, "Buried Piping Inspection – FRCT," Revision 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M34. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.26A and associated bases documents to determine consistency with GALL AMP XI.M34.

The project team reviewed those portions of the Buried Piping Inspection – FRCT program for which the applicant claims consistency with GALL AMP XI.M34 and found that they are consistent with the GALL Report AMP. Furthermore, the project team determined that the applicant's program provides assurance that aging effects are adequately managed so that the intended functions of buried pipe within the scope of license renewal at the OCGS are maintained consistent with the current licensing basis during the period of extended operation. The project team found that the applicant's buried pipe inspection – FRCT program conforms to the recommended GALL AMP XI.M34, with an exception as described below.

A7.3.0.3.2.7.3 Exceptions to the GALL Report

The applicant stated, in their response to RAI 2.5.1.19-1, the following exception to the GALL Report program elements:

Exception

Elements:	7. Corrective Actions 8. Confirmation Process 9. Administrative Controls
Exception:	These elements are not accomplished in accordance with the AmerGen quality assurance (QA) program and are not in accordance with the requirements of 10 CFR Part 50, Appendix B.

The GALL Report identified the following recommendations for the above program elements associated with the exception taken.

> The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with 10 CFR Part 50, Appendix B. The staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

The adequacy of the applicant's Quality Assurance Program associated with this program element is reviewed by DE staff and addressed in Section 3.0 of the SER related to the OCGS

LRA. In their response to RAI 2.5.1.19-1, the applicant stated that it will meet the guidance in Branch Technical Position IQMB-1, ?Quality Assurance for Aging Management Programs." On this basis, the project team found this exception acceptable.

A7.3.0.3.2.7.4 Enhancements

None.

A7.3.0.3.2.7.5 Operating Experience

The applicant stated, in Appendix D of the response to RAI 2.5.1.19-1, for the "operating experience" program element, the Buried Piping Inspection Program is a new program that will be effective in managing aging degradation for the period of extended operation by providing timely detection of aging effects and implementation of appropriate corrective actions prior to loss of system or component intended functions. To date, there have been no buried pipe leaks due to external degradation at the Forked River Combustion Turbine power plant. The buried piping at the Forked River Combustion Turbine power plant that is included in the scope of license renewal is the glycol filled cooling water piping that is routed below grade between the combustion turbines and the mechanical draft cooling towers. A head tank normally pressurizes the system, and the head tank includes level monitoring instrumentation. There is no history of buried pipe leaks in this system.

Based on plant operating experience, coatings and wrappings have provided adequate protection to the external surfaces of buried piping such that loss of material due to external corrosion has not been a concern. Thus inspection of buried piping when excavated for maintenance provides reasonable assurance that the intended functions will be maintained. Inspections will be performed within ten tears of entering the period of extended operation, and again within ten years after entering the period of extended operation, unless opportunistic inspections occur within each of these ten-year periods.

A7.3.0.3.2.7.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the buried pipe program in Appendix D of its response to RAI 2.5.1.19-1, Section A.1.26A, which stated that the buried piping inspection – FRCT aging management program is a new program that manages the external surface aging effects of loss of material for carbon steel piping and piping system components in a soil (external) environment. The program activities consist of preventive and condition-monitoring measures to manage the loss of material due to external corrosion for piping and piping system components in the scope of license renewal that are in a soil (external) environment. The program scope includes buried portions of glycol cooling water piping located at the Forked River Combustion Turbine station.

External inspections of buried components will occur opportunistically when they are excavated during maintenance. Within 10 years prior to entering the period of extended operation, inspection of buried piping will be performed unless an opportunistic inspection occurs within this ten-year period. Upon entering the period of extended operation, inspection of buried piping will again be performed within the next ten years, unless an opportunistic inspection occurs during this ten-year period. This program will be implemented prior to entering the period of extended operation.

The project team also reviewed the applicant’s updated license renewal commitment list in Appendix A of the response to RAI 2.5.1.19-1, and confirmed that this program is identified as a new program that will be implemented prior to the period of extended operation as item 57 of the commitments.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant’s buried piping inspection – FRCT aging management program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

The project team reviewed the UFSAR Supplement, found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR UFSAR Supplement table and as required by 10 CFR 54.21(d).

A7.3.0.3.2.7.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that the applicant has demonstrated that the effects of aging will be adequately managed. The buried pipe inspection program has been effective in monitoring the OCGS buried pipe and, is expected to be equally effective for the FRCT buried pipes. To date, there have been no leaks identified for the FRCT buried pipes. On the basis of its review of the UFSAR Supplement for this program, the project team also found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

A7.3.0.3.2.8 Structures Monitoring Program (B.1.31)

The OCGS structures monitoring program (AMP B.1.31) has been enhanced to include FRCT and Met Tower components that were identified as being in the scope of license renewal. The project team’s audit and review results for the OCGS structures monitoring program are provided in Section 3.0.3.2.24 of the OCGS audit and review report.

A7.3.0.3.2.9 Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.1.36)

The OCGS Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program (AMP B.1.36) has been enhanced to include FRCT components that were identified as being in the scope of license renewal. The project team’s audit and review results for the OCGS Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program are provided in Section 3.0.3.1.10 of the OCGS audit and review report.

A7.3.0.3.2.10 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components – FRCT (B.1.38)

In the November 11, 2005, supplemental response to NRC RAI 2.5.1.19-1, Appendix D, Section B.1.28, the applicant stated that FRCT AMP B.1.38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components – FRCT," is a new plant program that will be consistent with GALL AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components.”

A7.3.0.3.2.10.1 Program Description

In the November 11, 2005, supplemental response to NRC RAI 2.5.1.19-1, the applicant stated that the program as implemented for the Forked River combustion turbine power plant will consist of visual inspections of the internal surfaces of steel piping, valve bodies, ductwork, filter housings, fan housings, damper housings, mufflers and heat exchanger shells that are not covered by other aging management programs. These components are subject to an internal environment of indoor air that is assumed to include sufficient moisture content to result in loss of material aging effects. In addition, this program includes piping and mufflers with diesel engine exhaust gas as an internal environment. Internal inspections will be performed during scheduled maintenance activities when the surfaces are made accessible for visual inspection. The program includes visual inspections to assure that existing environmental conditions are not causing material degradation that could result in a loss of component intended functions.

A7.3.0.3.2.10.2 Consistency with the GALL Report

In the supplemental response to NRC RAI 2.5.1.19-1, the applicant stated that FRCT AMP B.1.38 is consistent with GALL AMP XI.M38, with exceptions.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for FRCT AMP B.1.38, including the program basis document, PBD-AMP-B.1.38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components – FRCT," Revision 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M38. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in FRCT AMP B.1.38 and associated bases documents to determine their consistency with GALL AMP XI.M38.

In reviewing this AMP, the project team noted that the description in the FRCT license renewal document did not discuss the inspection of elastomeric components as part of this program. The applicant was asked whether any elastomeric materials, such as flexible ducting and seals, are included in the scope of license renewal, and whether they are inspected as part of this program.

In its response, the applicant stated that there are two elastomeric components used in the Forked River combustion turbine mechanical systems subject to aging management. They are expansion joints and flexible connections exposed to fuel oil, outdoor air, and indoor air. NUREG-1801 line item VII.F4-6 (A-17) for elastomer seals and components exposed to an indoor air environment was used for the duct expansion joint. It calls for a plant specific aging management program. The plant specific aging management program used for inspection of these components is the Forked River Periodic Inspection Program.

The project team reviewed the applicant’s response and determined that elastomeric components requiring aging management in the Forked River combustion turbine systems are not included in the scope of FRCT AMP B.1.38; however, they will be managed by the FRCT periodic inspection aging management program, which is acceptable.

The project team reviewed those portions of the applicant’s Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components – FRCT program for which the applicant claims consistency with GALL AMP XI.M38 and found that they are consistent with the GALL Report AMP. Furthermore, the project team determined that the applicant’s program provides assurance that the aging effects for which this program is credited will be adequately managed. The project team found that the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components – FRCT program conforms to the recommended GALL AMP XI.M38, with the exception described below.

A7.3.0.3.2.10.3 Exceptions to the GALL Report

In the supplemental response to NRC RAI 2.5.1.19-1, the applicant stated the following exception to the GALL Report program:

Elements:	7. Corrective Actions 8. Confirmation Process 9. Administrative Controls
Exception:	These elements are not accomplished in accordance with the AmerGen quality assurance (QA) program and are not in accordance with the requirements of 10 CFR Part 50, Appendix B.

The GALL Report identified the following recommendations for the above program elements associated with the exception taken:

> The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with 10 CFR Part 50, Appendix B. The staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

The adequacy of the applicant's Quality Assurance Program associated with this program element is reviewed by DE staff and addressed in Section 3.0 of the SER related to the OCGS LRA. In their response to RAI 2.5.1.19-1, the applicant stated that it will meet the guidance in Branch Technical Position IQMB-1, ?Quality Assurance for Aging Management Programs." On this basis, the project team found this exception acceptable.

A7.3.0.3.2.10.4 Enhancements

None

A7.3.0.3.2.10.5 Operating Experience

In the November 11, 2005, supplemental response to NRC RAI 2.5.1.19-1, the applicant stated that in October 2001 (Unit 2 FRCT) and March 2004 (Unit 1 FRCT), GE Energy Services performed major inspection and maintenance activities, and documented all work performed in inspection reports dated January 4, 2002, and June 7, 2004, respectively. The equipment inspections included the turbine and its internals and support equipment. All work was carried out closely following the instructions and guidance found in the original equipment manufacturer's design, maintenance and inspection manuals. Acceptance criteria and corrective actions for these activities ensure that equipment is maintained within design specifications.

The applicant further stated that the Unit 1 inspection was a major maintenance inspection. The major inspection is the most comprehensive inspection that is performed on the combustion turbine units. The interval between major inspections is based on operating experience with these and similar combustion turbine installations, and factors that affect part life such as fuel type and starting frequency. The purpose of this type of maintenance inspection is to identify equipment degradation, and if degradation is identified the affected component is replaced or refurbished in accordance with manufacturers specifications such that the unit will perform reliably through the next operating interval. This was the first major inspection that was performed on the unit since initial installation in 1988.

The applicant further stated that during the Unit 1 inspection, bare paint spots with surface rust were identified in the filter housing, and were cleaned and touched up with new paint to prevent further rusting. The exhaust frame fan housings were cleaned and inspected, and no degradation was identified. Corrosion was identified in the compressor bleed valves that impacted smooth valve operation, but the valve body pressure boundary was not affected, and the valves were refurbished and reused. Ventilation fans were refurbished, and no issues with fan housing integrity were identified.

The applicant further stated that the Unit 2 inspection was a fuel nozzle and combustion section inspection. The Unit 2 inspection found the inlet filter housing to be in good condition, with no visual defects. The inspection included a borescope and combustion inspection, removal of exhaust frame cooling piping and disconnection of the fuel lines for inspection, and fuel nozzle inspection, repair, and testing. Unit 2 began a major outage inspection in October 2005. During the outage, with many components disassembled, components were visually inspected for signs of age related degradation. The internal surfaces of disassembled ductwork, fan housings and several damper housings were observed and did not show signs of significant corrosion. The turbine inlet air filters were replaced during the outage, and the coated internal surfaces of the filter housing were inspected and found to be in good condition. Internal surfaces of frame cooling piping were also observed to be in good condition, with minor surface rust and no significant pitting or loss of wall thickness. The internal surfaces of the diesel starter engine exhaust piping and muffler were also observed to be in good condition, with surface rust and no signs of significant pitting or wall-thinning.

The applicant further stated that the operating experience with the Forked River combustion turbines includes a significant number of past inspection activities of steel components in the indoor air and diesel exhaust environment. The documented inspection results provide objective evidence that existing environmental conditions are not causing material degradation that could result in a loss of component intended functions. Past inspections have been performed at a frequency as long at 16 years, with the units performing reliably between inspections. Implementation of this new program will assure that these inspections are continued on a more conservative frequency of 10 years, providing reasonable assurance that the aging effects will be adequately managed for the period of extended operation.

The project team reviewed the operating experience provided for the FRCT to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience, and discussions with the applicant's technical staff, the project team determined that the applicant’s Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components – FRCT program will adequately manage the aging effects that are identified in the FRCT AMRs for which this AMP is credited.

A7.3.0.3.2.10.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components – FRCT program in the November 11, 2005, supplemental response to NRC RAI 2.5.1.19-1, Appendix D, Section A.1.38, which states that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components – FRCT program is a new program that will provide a means of confirming the aging effects of loss of material and loss of heat transfer are either not occurring or are progressing so slowly as to not have an effect on the intended function of the combustion turbine fuel oil and lubricating oil system components within the period of extended operation. Additionally, this program will address potentially long incubation periods for loss of material and loss of heat transfer aging effects.

The applicant's UFSAR further stated that the One-Time Inspection – FRCT program will provide measures to verify that an aging management program is not needed, confirm the effectiveness of existing activities, or determine that degradation is occurring which will require evaluation and corrective action. The program will be implemented prior to the period of extended operation.

The applicant's UFSAR further stated that inspection methods will include visual examination or volumetric examinations. Inspections will be performed by qualified personnel using procedures developed consistent with the quality classification of the Forked River combustion turbines. Acceptance criteria will be in accordance with design standards for the combustion turbines and manufacturer's recommendations. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components – FRCT program provides for the evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could jeopardize an intended function before the end of the period of extended operation. Should aging effects be detected, the program will initiate actions to characterize the nature and extent of the aging effect and determine what subsequent monitoring is needed to ensure intended functions are maintained during the period of extended operation.

The project team also reviewed the applicant's updated license renewal commitment list in Appendix A of the supplemental response to RAI 2.5.1.19-1, and confirmed that this program is identified as a new program that will be implemented prior to the period of extended operation as item 58 of the commitments.

The project team reviewed the UFSAR Supplement for FRCT AMP B.1.38, found that it was consistent with the GALL Report, and determined that it provided an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

A7.3.0.3.2.10.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report are consistent with the GALL Report. In addition, the project team reviewed the exception and the associated justifications and determined that the AMP, with the exception, is adequate to manage the aging effects for which it is credited. The project team also reviewed the UFSAR Supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

A7.3.0.3.2.11 Lubricating Oil Analysis – FRCT (B.1.39)

In the applicant's response to NRC RAI 2.5.1.19-1 related to the OCGS LRA, dated November 11, 2005, Appendix D, Section B.1.39, the applicant stated that OCGS AMP B.1.39, ?Lubricating Oil Analysis Program – FRCT," aging management program is a new program that is consistent with GALL AMP XI.M39, ?Lubricating Oil Analysis Program," with exceptions.

A7.3.0.3.2.11.1 Program Description

In their response to RAI 2.5.1.19-1, the applicant stated that this program will include measures to verify the oil environment in mechanical equipment is maintained to the required quality. The Lubricating Oil Analysis Program – FRCT maintains oil systems contaminants (primarily water and particulates) within acceptable limits, thereby preserving an environment that is not conducive to loss of material, cracking, or reduction in heat transfer. Lubricating oil testing activities include sampling and analysis of lubricating oil for detrimental contaminants. The presence of water or particulates may also be indicative of in leakage and corrosion product buildup.

A7.3.0.3.2.11.2 Consistency with the GALL Report

In their response to RAI 2.5.1.19-1, the applicant stated that the OCGS AMP B.1.39 is consistent with the GALL XI.M.39, with exceptions.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.39, including the program bases document PBD-AMP-B.1.39, ?Lubricating Oil Analysis Program – FRCT," Revision 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M39. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.39 and associated bases documents to determine consistency with GALL AMP XI.M39.

The project team reviewed those portions of the Lubricating Oil Analysis Program – FRCT program for which the applicant claims consistency with GALL AMP XI.M39 and found that they are consistent with the GALL Report AMP. Furthermore, the project team determined that the applicant's program ensures that combustion turbine oil systems will be effectively managed to provide an acceptable oil environment, so that the intended functions of components within the scope of license renewal at the FRCT station are maintained consistent with the current licensing basis during the period of extended operation. The project team found that the applicant's Lubricating Oil Analysis Program – FRCT program conforms to the recommended GALL AMP XI.M39, with the exceptions as described below.

A7.3.0.3.2.11.3 Exceptions to the GALL Report

The applicant stated in their response to RAI 2.5.1.19-1 that the exception to the GALL Report program elements is as follows:

Exception 1

Element: 3. Parameters Monitored or Inspected

Exception: Parameters Monitored or Inspected requires the flash point be measured for the lubricating oils. Flash Point is not measured for lubricating oils in service, since this is a quality control measurement when purchasing new oil. It is not a primary measurement to determine the presence of water or contaminants, which are the concerns for controlling the environment of concern.

The GALL Report identified the following recommendation for the parameters monitored or inspected program element associated with the exception taken:

> 3. *Parameters Monitored or Inspected*: For components with periodic oil changes in accordance with manufacturer's recommendations, a particle count and check for water are performed to detect evidence of abnormal wear rates, contamination by moisture, or excessive corrosion. For components that do not have regular oil changes, viscosity, neutralization number, and flash point are also determined to verify the oil is suitable for continued use. In addition, analytical ferrography and elemental analysis are performed to identify wear particles.

The applicant stated that in their response to RAI 2.5.1.19-1 that no components with periodic oil changes were identified to have intended functions. Components with intended functions that do not have regular oil changes are supplied oil from the lubricating oil system. A particle count and check for water will be performed on the lubricating oil in the lubricating oil system to detect evidence of abnormal wear rates, contamination by moisture, or excessive corrosion. In addition, viscosity, and neutralization number will be determined to verify the oil is suitable for continued use. Wear particles will be identified through analytical ferrography, and elemental analysis. The applicant takes exception to the Flash Point monitoring recommendation specified in the GALL since this is a quality control measurement when purchasing new oil and is not a primary measurement to determine presence of contaminants.

The project team does not agree with the applicant's position. The project team determined that basis provided for exceptions is not valid since the flash point of an industrial lubricant is an important test to determine if light-end hydrocarbons are getting into the oil through seal leaks or other means. It is an effective way to monitor seal performance in light end hydro-carbon compressors. Low flash points pose a safety hazard in the event of component failure that can generate heat above the flash point of the oil, such as bearing failure. The applicant was asked to justify the reason for not monitoring the flash point of lubricating oil at the FRCT and why this exception is acceptable to manage the effects of aging for which it is credited. In its letter dated April 17, 2006 (ML061150320), the applicant committed to revise the Lubricating Oil Analysis Program – FRCT in LRA B.1.39 to include measurement of flash point. **This is Audit Commitment A7.3.0.3.2.11-1.**

<u>Exception 2</u>

Elements: 7. Corrective Actions
8. Confirmation Process
9. Administrative Controls

Exception: These elements are not accomplished in accordance with the AmerGen quality assurance (QA) program and are not in accordance with the requirements of 10 CFR Part 50, Appendix B.

The GALL Report identified the following recommendations for the above program elements associated with the exception taken.

> The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with 10 CFR Part 50, Appendix B. The staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

The adequacy of the applicant's Quality Assurance Program associated with this program element is reviewed by DE staff and addressed in Section 3.0 of the SER related to the OCGS LRA. In their response to RAI 2.5.1.19-1, the applicant stated that it will meet the guidance in Branch Technical Position IQMB-1, ?Quality Assurance for Aging Management Programs." On this basis, the project team found this exception acceptable.

A7.3.0.3.2.11.4 <u>Enhancements</u>

None.

A7.3.0.3.2.11.5 <u>Operating Experience</u>

The applicant stated in their response to NRC RAI 2.5.1.19-1 that the Lubricating Oil Analysis Program – FRCT is a new program that will be effective in managing aging degradation for the period of extended operation by providing periodic sampling and analysis of lubricating oil to provide timely detection of degradation in lubricating oil properties and take appropriate corrective actions prior to loss of system or component intended functions. In October 2001 (Unit 2 FRCT) and March 2004 (Unit 1 FRCT), GE Energy Services performed major inspection and maintenance activities and documented all work performed in inspection reports dated January 4, 2002, and June 7, 2004, respectively. The equipment inspections included the turbine and its internals and support equipment. All work was carried out closely following the instructions and guidance found in the original equipment manufacturer's design, maintenance and inspection manuals. Acceptance criteria and corrective actions for these activities ensure that equipment is maintained within design specifications.

The Unit 1 inspection was a major maintenance inspection. This was the first major inspection that was performed on the unit since initial installation in 1988. During the Unit 1 inspection, the emergency DC lubricating oil pump was removed and sent to the General Electric service shop for cleaning, inspection and repairs. The GE report does not indicate any issues associated with degradation of this pump casing. The combustion turbine lubricating oil system was drained, cleaned and inspected. Various pumps were inspected, and the lubricating oil coolers were cleaned. No degradation of these components was identified. The main lubricating oil pump was disassembled and inspected, and no defects were observed.

The Unit 2 inspection was a fuel nozzle and combustion section inspection. The lubricating oil filters were replaced. The GE report does not identify any issues with the lubricating oil system or components. Unit 2 began a major outage inspection in October 2005. During the outage, with many components disassembled, components were visually inspected for signs of age related degradation. The internal surfaces of disassembled stainless steel piping and flexible hoses showed no signs of corrosion or wall thinning. The combustion turbine lubricating oil heat exchangers were disassembled, cleaned and inspected. The carbon steel and copper alloy heat exchanger components normally exposed to lubricating oil were found to be in excellent condition. The standby heat exchanger that is not normally in service was found to have some minor accumulation of sediment that was cleaned off. Carbon steel pump casings that are normally submerged in the lubricating oil reservoir were visually observed to be in excellent condition, with no signs of corrosion. The carbon steel internal surfaces of the lubricating oil reservoir were also observed to be in excellent condition, with no signs of corrosion.

The operating experience with the combustion turbine system components subject to a lubricating oil environment demonstrates that the combustion turbine lubricating oil systems have not experienced significant intrusion of water and contaminants that would result in aging degradation. This new program will provide additional assurance that water and contaminant concentrations are minimized, such that age related degradation will continue to be minimized.

The Lubricating Oil Analysis Program – FRCT will monitor for adverse trends in performance. Problems identified will not cause impact to the intended functions of the Forked River Combustion Turbine power plant, and adequate corrective actions will be taken to prevent recurrence. There is sufficient confidence that the implementation of the Lubricating Oil Analysis Program – FRCT will effectively maintain oil systems contaminants (primarily water and particulates) within acceptable limits.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant’s Lubricating Oil Analysis Program – FRCT program will adequately manage the aging effects/mechanism that are identified in the OCGS LRA for which this AMP is credited.

A7.3.0.3.2.11.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the Lubricating Oil Analysis Program – FRCT program in their response to NRC RAI 2.5.1.19-1 which stated that the aging management program is a new program that includes measures to verify the oil environment in mechanical equipment is maintained to the required quality. The Lubricating Oil Analysis Program – FRCT maintains oil systems contaminants (primarily water and particulates) within acceptable limits, thereby preserving an environment that is not conducive to loss of material, cracking, or reduction in heat transfer. Lubricating oil testing activities include sampling and analysis of lubricating oil for detrimental contaminants. The presence of water or particulates may also be indicative of inleakage and corrosion product buildup. This program is augmented by the one time inspection – FRCT (B.1.24A) program, to verify the effectiveness of the Lubricating Oil Analysis Program – FRCT. This program will be implemented prior to the period of extended operation.

The project team also reviewed the applicant’s updated license renewal commitment list in Appendix A of the supplemental response to RAI 2.5.1.19-1, and confirmed that this program is identified as a new program that will be implemented prior to the period of extended operation as item 59 of the commitments. The applicant committed to revise this item to reflect the commitment specified in A7.3.0.3.2.11-1.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant’s Lubricating Oil Analysis Program – FRCT program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

The project team reviewed the UFSAR Supplement for OCGS AMP B.1.39 found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR FSAR Supplement table and as required by 10 CFR 54.21(d).

A7.3.0.3.2.11.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that those program elements for which the applicant claims consistency with the GALL Report, are consistent with the GALL Report. In addition, the project team has reviewed commitment A7.3.0.3.2.11-1, the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. The project team also reviewed the UFSAR Supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

A7.3.0.3.2.12 Buried Piping and Tank Inspection-Met Tower Repeater Engine Fuel Supply (OCGS AMP B.1.26B)

In the applicant's response to NRC RAI 2.5.1.15-1 related to the OCGS LRA, dated December 9, 2005, Appendix D, Section B.1.26B, the applicant stated that OCGS AMP B.1.26B, "Buried Piping and Tank Inspection – Met Tower Repeater Engine Fuel Supply," which is consistent with GALL AMP XI.M34, ?Buried Piping and Tanks Inspection," with exceptions.

A7.3.0.3.2.12.1 Program Description

In their response to RAI 2.5.1.15-1, the applicant stated that the Buried Piping and Tank Inspection – Met Tower Repeater Engine Fuel Supply aging management program is a new aging management program that relies on coating, wrapping and periodic inspection as a preventive measure, and to mitigate and manage the effects of corrosion on the pressure-retaining capacity of carbon steel and copper piping and fittings, and carbon steel tank, in a soil (external) environment. External coatings and wrappings are maintained in accordance with standard industry practices. External inspections of buried piping components will occur opportunistically when excavated during maintenance. Within 10 years prior to entering the period of extended operation, inspection of buried piping components will be performed unless an opportunistic inspection occurs within this ten-year period. Upon entering the period of extended operation, inspection of buried piping components will again be performed within the next ten years, unless an opportunistic inspection occurs during this ten-year period. The aging management program activities will be coordinated with First Energy, as necessary, pursuant to an Easement, License, and Restrictive Covenant Agreement.

A7.3.0.3.2.12.2 Consistency with the GALL Report

In their response to RAI 2.5.1.15-1, the applicant stated that the OCGS AMP B.1.26B is consistent with the GALL AMP XI.M34, with exceptions.

The project team interviewed the applicant's technical staff and reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.1.26B, including the program bases document PBD-AMP-B.1.26B, "Buried Piping and Tank Inspection – Met Tower Repeater Engine Fuel Supply," Revision 0, which provides an assessment of the AMP elements' consistency with GALL AMP XI.M34. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in OCGS AMP B.1.26B and associated bases documents to determine consistency with GALL AMP XI.M34.

The project team reviewed those portions of the Buried Piping and Tank Inspection – Met Tower Repeater Engine Fuel Supply Program for which the applicant claims consistency with GALL AMP XI.M34 and found that they are consistent with the GALL Report AMP. Furthermore, the project team determined that the applicant's this program provides assurance that aging effects are adequately managed so that the intended functions of buried pipe within the scope of license renewal at the OCGS are maintained consistent with the current licensing basis during the period of extended operation. The project team found that the applicant's buried pipe inspection – Met tower repeater engine fuel supply program conforms to the recommended GALL AMP XI.M34, with the exceptions as described below.

A7.3.0.3.2.12.3 <u>Exceptions to the GALL Report</u>

The applicant stated in their response to RAI 2.5.1.15-1 the following exception to the GALL Report program elements:

<u>Exception 1</u>

Elements:	2. Preventive Actions 3. Parameters Monitored or Inspected 4. Detection of Aging Effects
Exception:	NUREG-1801, Section X1.M.34, ?Buried Piping and Tanks Inspection," AMP relies on preventive measures such as coatings and wrappings, however portions of this piping may not be coated or wrapped. Inspections of buried piping that is not wrapped will inspect for loss of material due to general, pitting, crevice, and MIC.

The GALL Report identified the following recommendations for the above program elements ?Preventive Actions," Parameters Monitored or Inspected," and ?Detection of Aging Effects." associated with the exception taken:

> 2. *Preventive Action*: In accordance with industry practice, underground piping and tanks are coated during installation with a protective coating system, such as coal tar enamel with a fiberglass wrap and a kraft paper outer wrap, a polyolifin tape coating, or a fusion bonded epoxy coating to protect the piping from contacting the aggressive soil environment.
>
> 3. *Parameters Monitored or Inspected*: The program monitors parameters such as coating and wrapping integrity that are directly related to corrosion damage of the external surface of buried steel piping and tanks. Coatings and wrappings are inspected by visual techniques. Any evidence of damaged wrapping or coating defects, such as coating perforation, holidays, or other damage, is an indicator of possible corrosion damage to the external surface of piping and tanks.
>
> 4. *Detection of Aging Effects*: Inspections performed to confirm that coating and wrapping are intact are an effective method to ensure that corrosion of external surfaces has not occurred and the intended function is maintained. Buried piping

> and tanks are opportunistically inspected whenever they are excavated during maintenance. When opportunistic, the inspections are performed in areas with the highest likelihood of corrosion problems, and in areas with a history of corrosion problems, within the areas made accessible to support the maintenance activity.
>
> The applicant's program is to be evaluated for the extended period of operation. It is anticipated that one or more opportunistic inspections may occur within a ten-year period. Prior to entering the period of extended operation, the applicant is to verify that there is at least one opportunistic or focused inspection is performed within the past ten years. Upon entering the period of extended operation, the applicant is to perform a focused inspection within ten years, unless an opportunistic inspection occurred within this ten-year period. Any credited inspection should be performed in areas with the highest likelihood of corrosion problems, and in areas with a history of corrosion problems.

The applicant stated that in their response to RAI 2.5.1.15-1 and in the program basis document PBD-AMP-B.1.26B, Revision 0, that in accordance with industry practice, portions of the underground piping and tank at the Forked River meteorological tower were either procured with coating or coated during installation with a protective coating system to protect the piping and tank from contacting the potentially aggressive soil environment. Portions of the piping that are not coated or wrapped will be inspected for loss of material due to general, pitting, crevice, and MIC. Inspections will be performed to confirm that coating and wrapping are intact, and to determine the extent of potential corrosion of buried piping components that are not coated or wrapped. These inspections are an effective method to ensure that corrosion of external surfaces has not occurred and the intended function is maintained. The buried piping and tank will be opportunistically inspected whenever excavated for maintenance. The inspections will be performed on all of the areas made accessible to support the maintenance activity.

The project team noted that the applicant follows the recommendations specified in the GALL Report for inspections of underground piping coatings and wrappings and the underground piping that are not coated or wrapped will be inspected for loss of material due to general, pitting, crevice, and MIC. On this basis, the project team found this exception acceptable.

<u>Exception 2</u>

Elements:	7. Corrective Actions 8. Confirmation Process 9. Administrative Controls
Exception:	These elements are not accomplished in accordance with the AmerGen quality assurance (QA) program and are not in accordance with the requirements of 10 CFR Part 50, Appendix B.

The GALL Report identified the following recommendations for the above program elements associated with the exception taken.

> The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with 10 CFR Part 50, Appendix B. The staff finds the requirements of 10 CFR Part 50,

Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

The adequacy of the applicant's Quality Assurance Program associated with this program element is reviewed by DE staff and addressed in Section 3.0 of the SER related to the OCGS LRA. In their response to RAI 2.5.1.19-1, the applicant stated that it will meet the guidance in Branch Technical Position IQMB-1, ?Quality Assurance for Aging Management Programs." On this basis, the project team found this exception acceptable.

A7.3.0.3.2.12.4 Enhancements

None.

A7.3.0.3.2.12.5 Operating Experience

The applicant stated, in Appendix D of the response to RAI 2.5.1.15-1, for the "operating experience" program element, the buried pipe inspection – Met tower repeater engine fuel supply system aging management program is a new program that will be effective in managing aging degradation for the period of extended operation by providing timely detection of aging effects and implementation of appropriate corrective actions prior to loss of system or component intended functions. The buried piping and tank at the Forked River Met Tower that is included in the scope of license renewal is the below grade propane filled piping and tank next to the Forked River meteorological tower. There is no history of buried pipe or tank leaks in this system.

Based on Forked River meteorological tower repeater engine fuel supply buried piping and tank operating experience, loss of material due to external corrosion has not been a concern. Inspection of the buried piping and tank when excavated for maintenance therefore provides reasonable assurance that the intended functions will be maintained. Inspections will be performed within 10 years of entering the period of extended operation, and again within ten years after entering the period of extended operation, crediting opportunistic inspections that may occur within each of these ten-year periods.

A7.3.0.3.2.12.6 UFSAR Supplement

The applicant provided its UFSAR Supplement for the buried pipe program in Appendix D of its response to RAI 2.5.1.15-1, Section A.1.26B, which stated that the buried piping and tank inspection – Met tower repeater engine fuel supply aging management program is a new program that manages the external surface aging effects of loss of material for carbon steel and copper piping and fittings, and carbon steel tank, in a soil (external) environment. The program activities consist of preventive and condition-monitoring measures to manage the loss of material due to external corrosion for the piping, fittings, and tank in the scope of license renewal that are in a soil (external) environment. The program scope includes buried portions of the meteorological tower repeater engine fuel supply (propane) piping and tank located at the Forked River meteorological tower.

External inspections of buried components will occur opportunistically when they are excavated during maintenance. Within 10 years prior to entering the period of extended operation, inspection of buried piping components will be performed unless an opportunistic inspection occurs within this ten-year period. Upon entering the period of extended operation, inspection of buried piping components will again be performed within the next ten years, unless an opportunistic inspection occurs during this ten-year period. This program will be implemented prior to entering the period of extended operation.

The project team also reviewed the applicant's updated license renewal commitment list in Appendix A of the response to RAI 2.5.1.15-1, and confirmed that this program is identified as a new program that will be implemented prior to the period of extended operation as item 61 of the commitments.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant's buried piping and tank inspection – Met tower repeater engine fuel supply aging management program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

The project team reviewed the UFSAR Supplement, found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR UFSAR Supplement table and as required by 10 CFR 54.21(d).

A7.3.0.3.2.12.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that the applicant has demonstrated that the effects of aging will be adequately managed. The buried pipe inspection program has been effective in monitoring the OCGS buried pipe and, is expected to be equally effective for the met. tower repeater engine fuel supply buried pipe and tanks. To date, there have been no leaks identified for the met. tower repeater engine fuel supply buried pipe and tanks. On the basis of its review of the UFSAR Supplement for this program, the project team also found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

A7.3.0.3.3 *AMPs That Are Not Consistent with the GALL Report or Not Addressed in the GALL Report*

A7.3.0.3.3.1 Periodic Monitoring of Combustion Turbine Power Plant – Electrical (B.1.37)

In the applicant's response to NRC RAI 2.5.1.19-1 related to Section B.1.37 of Appendix D to the OCGS LRA, dated October 12, 2005, the applicant stated that OCGS AMP B.1.37, ?Periodic Monitoring of Combustion Turbine Power Plant – Electrical" is a new plant program that will include elements of GALL AMPs XI.E1, ?Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," XI.E3, ?Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," and XI.E4, ?Metal Enclosed Buses."

A7.3.0.3.3.1.1 Program Description

In its response to RAI 2.5.1.19-1, the applicant stated that this program will be used to manage aging effects for the electrical commodities that support FRCT operation. The new AmerGen Periodic Monitoring of Combustion Turbine Power Plant – Electrical program, the existing structures monitoring program, and the new Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program will be used to manage aging effects for the electrical commodities that support FRCT operation. This AmerGen program will include elements of GALL AMP XI.E1 for accessible electrical cables and connections; XI.E3 for manholes, pits, and cable trenches; and XI.E4 for the phase bus, connections, and phase bus insulators. This AmerGen program will inspect accessible electrical cables and connections before the period of extended operation, with an inspection frequency of at least once every 10 years.

This AmerGen program will inspect manholes, pits, and cable trenches containing inaccessible medium-voltage cables located on the FRCT site for water collection so that draining or other corrective actions can be taken. Inspections for water collection will be performed at least once every 2 years, and the frequency of inspection will be adjusted based on the results obtained. The first inspections will be completed before the period of extended operation.

This AmerGen program will also inspect the accessible phase bus, connections, and insulators before the period of extended operation, with an inspection frequency of at least once every 5 years. Inspection of the phase bus enclosure external surfaces will be performed under the existing structures monitoring program (AMP-B.1.31). The first inspection will be performed before the period of extended operation, with an inspection frequency of at least once every 4 years.

The following represents the AMP B.1.36 scope for 13.8 kV cables that distribute the output of the FRCT to both the OCGS SBO transformer and the 230 kV switchyard. Inaccessible medium-voltage cable circuits supporting the FRCT and the associated manholes, pits, and trenches located on the OCGS site will be tested or inspected by the new Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program (AMP-B.1.36). The first tests and inspections will be performed before the period of extended operations, with a cable test frequency of at least once every 10 years, and a manhole, pit, and trench inspection frequency of at least once every 2 years. These aging management activities ensure the continued availability of the FRCTs as the alternate ac source in the event of an SBO at OCGS.

A7.3.0.3.3.1.2 Consistency with the GALL Report

In FRCT program basis document PBD-AMP-B.1.37, ?Periodic Monitoring of Combustion Turbine Power Plant – Electrical," Revision 0, the applicant stated that FRCT AMP B.1.37, "Periodic Monitoring of Combustion Turbine Power Plant – Electrical" is consistent with GALL AMPs XI.E1, XI.E3, and XI.E4.

The project team interviewed the applicant's technical staff and reviewed the documents listed in Attachment 5 of this audit and review report, in whole or in part, including program basis document PBD-AMP-B.1.37, ?Periodic Monitoring of Combustion Turbine Power Plant – Electrical," Revision 0. The project team reviewed the applicant's comparison of the FRCT program with the elements of the corresponding NUREG-1801 Chapter XI aging management programs XI.E1, XI.E3, and XI.E4. Specifically, the project team reviewed the program elements (see Section 3.0.2.1 of this audit and review report) contained in FRCT AMP B.1.37 to determine their consistency with GALL AMPs XI.E1, X1.E3, and X1.E4.

The project team reviewed those portions of the applicant's program for which the applicant claims consistency with GALL AMPs XI.E1, X1.E3, and X1.E4 and found that they are consistent with these GALL Report AMPs. The project team's review of cable testing portions of NUREG-1801 Section XI.E3 program elements and the structures monitoring associated with electrical commodities, as scoped by NUREG-1801 Section XI.S6 program elements are discussed in Section 3.0.3 of this OCGS audit and review report. The project team asked the applicant whether the GALL X1.E4 program elements included phase bus enclosure internal surfaces inspections. The applicant stated that this program also includes inspection of the internal portion of the metal enclosed buses to identify age related degradation of insulating and metallic components, excessive dust buildup and foreign debris, and evidence of moisture debris intrusion. On the basis of its review, the project team determined that the applicant's Periodic Monitoring of Combustion Turbine Power Plant – Electrical program will effectively manage the aging of accessible cables and connections; inaccessible medium-voltage cables; and phase bus and connections, phase bus insulators, and phase bus enclosure internal surfaces such that there is reasonable assurance that the intended functions of the electrical commodities supporting the FRCTs will be maintained consistent with the current licensing basis during the period of extended operation. The project team found that the applicant's Periodic Monitoring of Combustion Turbine Power Plant – Electrical Program conforms to the recommendations in GALL AMPs XI.E1, X1.E3, and X1.E4.

A7.3.0.3.3.1.3 Exceptions to the GALL Report

None

A7.3.0.3.3.1.4 Enhancements

None

A7.3.0.3.3.1.5 Operating Experience

In its response to RAI 2.5.1.19-1, the applicant stated that while this is a new program, FRCT has not experienced a cable- or bus-related failure during its period of operation. The applicant also stated that a 2004 inspection involved major rework and repair of the exhaust plenum after and forward walls, including a complete rebuild and rewiring of the load compartment and junction boxes, as well as extensive alignment activities. These major efforts ensured that the FRCT cables and connections were in optimal condition when returned to service. Lessons learned from routine inspections are incorporated into the future outage scope. A review of the applicant's corrective action documents did not indicate the occurrence of aging degradation with electrical commodities at the FRCT power plant or a combustion turbine reliability below the 95 percent requirement.

The project team reviewed the operating experience provided in OCGS PBD-AMP-B.1.37 and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant's periodic monitoring of combustion turbine power plant-electrical program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

A7.3.0.3.3.1.6 UFSAR Supplement

The applicant provided its UFSAR Supplements for the Periodic Monitoring of Combustion Turbine Power Plant – Electrical program in its response to RAI 2.5.1.19-1. The new Periodic Monitoring of Combustion Turbine Power Plant – Electrical program will be used in conjunction with the existing structures monitoring program and the new Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program to manage aging effects for the electrical commodities that support FRCT operation. The program consists of visual inspections of accessible electrical cables and connections exposed in enclosures, pits, manholes, and pipe trenches for embrittlement, discoloration, cracking, or surface contamination; visual inspections of manholes, pits, and cable trenches (located on the FRCT site) for inaccessible medium-voltage cables, for water collection; and visual inspections of accessible phase bus, connections, and insulators for melting or other signs of heat effects on the tape covering bus connections, cracking of thermoplastic, or degradation of insulators. Phase bus enclosure external surfaces will be inspected by the existing structures monitoring program for signs of corrosion. The inaccessible medium-voltage cable circuits supporting the FRCT and the associated manholes, pits, and trenches located on the OCGS site will be tested or inspected by the new Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program for signs of insulation degradation and for prevention of wetted environments.

The new combustion turbine power plant – electrical program will be implemented before the period of extended operation. Inspections of manholes, pits, and trenches located on the FRCT site will be performed at least once every 2 years for the accumulation of water, and the frequency will be adjusted based on the results obtained. Cable and connection inspections will be implemented before the period of extended operation with a frequency of at least once every 10 years. Accessible phase bus, connections, and insulator inspections will be performed at least once every 5 years. Phase bus enclosure external surface inspections will be performed at the frequency specified in the structures monitoring program. Inaccessible medium-voltage cable circuits and the associated manhole, pit, and trench tests and inspections will be performed at the frequency specified in the Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program.

The project team also reviewed the license renewal commitment list in Section A.5 of the OCGS LRA to confirm that this new program will be implemented before the period of extended operation, and noted that it is Item 43 on the list of commitments.

The project team reviewed the UFSAR Supplement, found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program as identified in the SRP-LR UFSAR Supplement table and as required by 10 CFR 54.21(d).

A7.3.0.3.3.1.7 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that the applicant has demonstrated that the effects of aging will be adequately managed.

On the basis of its review of the UFSAR Supplement for this program, the project team also found that it provides an adequate summary description of the program as required by 10 CFR 54.21(d).

A7.3.0.3.3.2 Periodic Inspection Program – FRCT (B.2.5A)

In the applicant's response to NRC RAI 2.5.1.19-1 related to the OCGS LRA, dated November 11, 2005, Appendix D, Section B.2.05A, the applicant described OCGS AMP B.2.05A," Periodic Inspection Program – FRCT."

The applicant stated that OCGS AMP B.2.05 is a new program. The Periodic Inspection Program – FRCT aging management program will address Forked River Combustion Turbine power plant components in the scope of license renewal that require periodic monitoring of aging effects, and are not covered by other aging management programs. Activities will consist of a periodic inspection of selected components to verify integrity and confirm the absence of identified aging effects. The inspections will be condition monitoring examinations, intended to assure that existing environmental conditions are not causing material degradation that could result in a loss of intended functions. This program is used for the following:

- To confirm change in material properties due to aging is not occurring in elastomer expansion joints and flexible connections exposed to fuel oil, indoor air or outdoor air environments.

- To confirm reduction of heat transfer due to aging is not occurring in heat exchangers exposed to indoor air or outdoor air environments.

- To confirm loss of material in various steel and stainless steel components subject to an intermittent combustion turbine exhaust gas environment is monitored such that there is no loss of component intended functions.

- To confirm loss of material in copper heat exchanger components subject to an indoor air or outdoor air environment is monitored such that there is no loss of component intended functions.

- To confirm cracking in stainless steel components subject to intermittent combustion turbine exhaust gas environment is monitored such that there is no loss of component intended functions.

The program elements will include (a) determination of appropriate inspection sample size, (b) identification of inspection locations, (c) selection of examination technique, with acceptance criteria, and (d) evaluation of results to determine the need for additional inspections or other corrective actions. The sample size will be based on aspects such as the specific aging effect, location, existing technical information, materials of construction, service environment, or previous failure history. The inspection samples will include locations where the most severe aging effect(s) would be expected to occur. The inspection locations will be based on aspects such as similarity of materials of construction, fabrication, operating environment, or aging effects. Inspection methods may include visual examination, surface or volumetric examinations, or other established Non-Destructive Examination (NDE) techniques.

This program will assess change in material properties, loss of material, cracking and reduction of heat transfer of FRCT mechanical components. For components in the scope of this program, an inspection will be conducted to confirm change in material properties, loss of material, cracking, and reduction of heat transfer is not occurring, or the aging effect is occurring at a rate so as not to affect the component intended function. The program will provide inspection criteria, require evaluation of the results of the inspections, and provide recommendations for additional inspections, as necessary. Inspections will be scheduled to coincide with major combustion turbine maintenance inspections, when the subject components are made accessible. These inspections will be performed on a frequency not to exceed once every 10 years. The initial inspections associated with this program will be performed at the next major inspection outage for each unit. Based on the established inspection frequency of 10 years, the next inspection for CT Unit 1 will be performed by May 2014, and the next inspection for CT Unit 2 will be performed by November 2015.

The project team reviewed, in whole or in part, the documents listed in Attachment 5 of this audit and review report for OCGS AMP B.2.05A, including the program bases document PBD-AMP-B.05A, ?Periodic Inspection – FRCT,” Revision 0, and interviewed the applicant's technical staff.

A7.3.0.3.3.2.1 Review of the OCGS AMP B.2.05A Against the Program Elements

The project team reviewed OCGS AMP B.2.05A against the AMP elements found in SRP-LR, Appendix A.1, Section A.1.2.3 and SRP-LR Table A.1-1. The project team followed the reviewed process as described in the OCGS audit and review plan.

A7.3.0.3.3.2.1.1 Scope of Program

The ?scope of program” program element in Appendix A.1.2.3.1 of the SRP-LR recommends that the program scope include the specific structures and components addressed with this program.

The applicant stated in OCGS AMP B.2.05A, for the "scope of program" program element, that the scope of this program includes systems in the scope of license renewal that require periodic monitoring of aging effects, and are not covered by other existing periodic monitoring programs. Inspections will be performed at susceptible locations in the system.

The project team determined that the specific components for which the program manages aging effects are identified by the applicant, which satisfies the criterion as defined in Appendix A.1.2.3.1 of the SRP-LR. On this basis, the project team found that the applicant’s proposed program scope acceptable.

A7.3.0.3.3.2.1.2 Preventive Actions

The ?preventive actions” program element in Appendix A.1.2.3.2 of the SRP-LR are that (1) the activities for prevention and mitigation programs should be described, and (2) for condition or performance monitoring programs that do not rely on preventive actions, and thus, preventive actions need not be provided.

The applicant stated in OCGS AMP B.2.05A, for the "preventive actions" program element, that this program activities will be condition monitoring activities to detect degradation prior to change in material properties, loss of material, cracking and reduction of heat transfer aging effects as applicable for the material and environment. No preventive or mitigating attributes are associated with this program.

The project team determined that the preventive actions program element satisfies the criteria defined in Appendix A.1.2.3.2 of the SRP-LR. On this basis, the project team found that the applicant's preventive actions acceptable.

A7.3.0.3.3.2.1.3 Parameters Monitored or Inspected

The ?parameters monitored or inspected” program element in Appendix A.1.2.3.3 of the SRP-LR can be summarized as:

> The parameters to be monitored or inspected should be identified and linked to the degradation of the particular structure and component intended function(s).

For condition monitoring program, the parameter monitored or inspected should detect the presence and extent of aging effects.

For performance monitoring program, a link should be established between degradation of the particular structure or component intended function(s) and the parameter being monitored.

For prevention and mitigation programs, the parameter monitored should be the specific parameter being controlled to achieve prevention or mitigation of aging effects.

The applicant stated in OCGS AMP B.2.05A, for the "parameters monitored or inspected" program element, that this program will provide inspection for change in material properties, loss of material, cracking and reduction of heat transfer. Inspection procedures will be prepared in accordance with applicable codes, standards and inspection practices. Examination methods include visual examination of disassembled components, surface or volumetric examinations, or other established non-destructive examination techniques.

The project team determined that the preventive actions program element satisfies the criteria defined in Appendix A.1.2.3.3 of the SRP-LR. On this basis, the project team found that the applicant's description of the parameters monitored or inspected is acceptable.

A7.3.0.3.3.2.1.4 Detection of Aging Effects

The ?detection of aging effects" program element in Appendix A.1.2.3.4 of the SRP-LR can be summarized as:

Provide information that links the parameters to be monitored or inspected to the aging effects being managed.

Describe when, where, and how program data are collected (i.e., all aspects of activities to collect data as part of the program).

Link the method or technique and frequency, if applicable, to plant-specific or industry-wide operating experience.

Provide the basis for the inspection population and sample size when sampling is used to inspect a group of systems or components (SCs). The inspection population should be based on such aspects of the SCs as a similarity of materials of construction, fabrication, procurement, design, installation, operating environment, or aging effects.

The applicant stated in OCGS AMP B.2.05A, for the "detection of aging effects" program element, that this program includes inspections for change in material properties, loss of material, cracking and reduction of heat transfer will be performed on a representative sample of susceptible locations. Inspection for loss of material will consist of surface inspections, thickness measurements using ultrasonic testing, or visual examination of disassembled components.

A representative sample of locations will be inspected to confirm that unacceptable degradation is not occurring and the intended function of components will be maintained during the period of extended operation. Unacceptable inspection results will require that the sample size and locations be expanded until the extent of the problems is determined. The sample size and location expansion will be determined based on evaluations of the unacceptable inspection results. Inspections will be scheduled to coincide with major combustion turbine maintenance inspections, when the subject components are made accessible. These inspections will be performed on a frequency not to exceed once every 10 years.

The initial inspections associated with this program will be performed at the next major inspection outage for each unit. As discussed under Operating Experience (Element 10), the last combustion turbine (CT) Unit 1 major inspection outage was performed in 2004. The outage began in March 2004 and was completed in May 2004. The last CT Unit 2 major inspection outage began in October 2005 and is scheduled for completion in November 2005. All work was carried out closely following the instructions and guidance found in the original equipment manufacturers design, maintenance and inspection manuals, such that equipment is maintained within design specifications to provide reliable service until the next major maintenance inspection. Based on the extent and location of aging effects that were observed, and the as-left internal component conditions following the maintenance outages, additional internal inspections are not warranted prior to entering the period of extended operation. Based on the established inspection frequency of 10 years, the next inspection for CT Unit 1 will be performed by May 2014, and the next inspection for CT Unit 2 will be performed by November 2015.

The project team determined that this program element satisfies the criteria defined in Appendix A.1.2.3.4 of the SRP-LR. On this basis, the project team found that the applicant's description of the detection of aging effects is acceptable.

A7.3.0.3.3.2.1.5 Monitoring and Trending

The ?monitoring and trending” program element in Appendix A Section A.1.2.3.5 of the SRP-LR can be summarized as:

> Monitoring and trending activities should be described, and they should provide predictability of the extent of degradation and thus effect timely corrective or mitigative actions.
>
> This program element describes how the data collected are evaluated and may also include trending for a forward look. The parameter or indicator trended should be described.

The applicant stated in OCGS AMP B.2.05A, for the "monitoring and trending" program element, that results of the periodic inspection activities will be monitored. Indications of insufficient material wall thickness, change in material properties, cracking and reduction of heat transfer in excess of established acceptance criteria will require further evaluation. The evaluation will either demonstrate acceptability or specify the appropriate repair or replacement. Follow up examinations will be performed, if necessary, to determine the extent of the degraded condition, thus expanding the sample size and locations of Inspections.

The project team determined that for visual inspection, this program element satisfies the criteria defined in Appendix A.1.2.3.5 of the SRP-LR. On this basis, the project team found that the applicant's description of the monitoring and trending is acceptable.

A7.3.0.3.3.2.1.6 Acceptance Criteria

The ?acceptance criteria" program element in Appendix A.1.2.3.6 of the SRP-LR can be summarized as:

> The acceptance criteria of the program and its basis should be described. The acceptance criteria, against which the need for corrective actions will be evaluated, should ensure that the SC intended function(s) are maintained under all CLB design conditions during the period of extended operation.
>
> The program should include a methodology for analyzing the results against applicable acceptance criteria.
>
> Qualitative inspections should be performed to the same predetermined criteria as quantitative inspections by personnel in accordance with ASME Code and through approved site-specific programs.

The applicant stated in OCGS AMP B.2.05A, for the "acceptance criteria" program element, that results of the examinations will be evaluated to determine if change in material properties, loss of material, cracking or reduction of heat transfer aging is occurring, and if so, the rate at which the aging effect is occurring. Evaluation of the examination results will also a) determine the need for follow-up examinations to monitor the progression of aging degradation, and b) identify appropriate corrective actions, including repairs or replacements, to mitigate any excessive rates of aging degradation. Corrective actions, if necessary, would expand to include other components. Change in material properties, loss of material, cracking and reduction of heat transfer will be evaluated consistent with original design or evaluation codes and criteria, or manufacturers standards.

The project team reviewed this program element to determine whether or not it satisfies the criteria defined in Appendix A.1.2.3.6 of the SRP-LR. On this basis, the project team found that the applicant's description of the acceptance criteria is acceptable.

A7.3.0.3.3.2.1.7 Corrective Actions

The adequacy of the applicant's program associated with this program element is reviewed by the NRR/DE staff and addressed in Section 3 of the SER related to the OCGS LRA.

The project team reviewed other aspects of this program element to determine whether or not it satisfies the criteria defined in Appendix A.1.2.3.7 of the SRP-LR. The project team noted that the Forked River Combustion Turbines and supporting systems are non-safety-related and are not subject to 10 CFR Part 50 Appendix B requirements in the current licensing basis (CLB). AmerGen has elected not to include this program under the Oyster Creek 10 CFR Part 50 Appendix B Program. Instead, processes and procedures will be established to assure that conditions adverse to quality are promptly identified and corrected. Identified conditions that do not satisfy acceptance criteria will be documented, evaluated, and corrected as required to maintain the intended function of combustion turbines during the period of extended operation. In the case of significant conditions adverse to quality, the procedures will require that the cause of the condition be determined, actions to preclude repetition be taken, and the condition be reported to the appropriate level of management. In their response to RAI 2.5.1.19-1, the applicant stated that it will meet the guidance in Branch Technical Position IQMB-1, ?Quality

Assurance for Aging Management Programs." On this basis, the project team found that the applicant's description of the corrective actions is acceptable.

A7.3.0.3.3.2.1.8 Confirmation Process

The adequacy of the applicant's program associated with this program element is reviewed by the NRR/DE staff and addressed in Section 3 of the SER related to the OCGS LRA.

The project team reviewed other aspects of this program element to determine whether or not it satisfies the criteria defined in Appendix A.1.2.3.8 of the SRP-LR. The project team noted that the confirmation process for the Forked River Combustion Turbine will focus on follow-up actions that must be taken to verify effective implementation of corrective actions and preclude repetition of significant conditions adverse to quality. The established process and procedures will include the requirements that measures be taken to preclude repetition of significant conditions adverse to quality. These measures will include actions to verify effective implementation of the proposed corrective actions, determination of root cause, tracking open corrective actions to completion, and reviews of corrective action effectiveness.

In their response to RAI 2.5.1.19-1, the applicant stated that it will meet the guidance in Branch Technical Position IQMB-1, ?Quality Assurance for Aging Management Programs." On this basis, the project team found that the applicant's description of the confirmation process is acceptable.

A7.3.0.3.3.2.1.9 Administrative Controls

The adequacy of the applicant's program associated with this program element is reviewed by the NRR/DE staff and addressed in Section 3 of the SER related to the OCGS LRA. The project team noted that the Forked River Combustion Turbine procedures will include administrative controls that provide for formal review and approval of aging management activities.

The project team reviewed other aspects of this program element to determine whether or not it satisfies the criteria defined in Appendix A.1.2.3.9 of the SRP-LR. In their response to RAI 2.5.1.19-1, the applicant stated that it will meet the guidance in Branch Technical Position IQMB-1, ?Quality Assurance for Aging Management Programs." On this basis, the project team found that the applicant's description of the administrative controls is acceptable.

A7.3.0.3.3.2.1.10 Operating Experience

The ?operating experience" program element criteria in Appendix A.1.2.3.10 of the SRP-LR can be summarized as:

> Operating experience should provide objective evidence to support the conclusion that the effects of aging will be managed adequately so that the structure and component intended function(s) will be maintained during the period of extended operation.
>
> An applicant may have to commit to providing operating experience in the further for new programs to confirm their effectiveness.

The applicant stated, in the OCGS AMP B.2.5 LRA, for the "operating experience" program element, that the Periodic Inspection Program – FRCT aging management program is a new program that will be effective in managing aging degradation for the period of extended operation by providing timely detection of aging effects and implementation of appropriate corrective actions prior to loss of component intended functions. This program will be incorporated into current maintenance inspection practices, which have been demonstrated through operating experience to be effective in managing age related degradation such that the intended functions of the combustion turbines have been maintained.

The applicant stated in the OCGS LRA that in October 2001 (Unit 2 FRCT) and March 2004 (Unit 1 FRCT), GE Energy Services performed inspection and maintenance activities and documented all work performed in inspection reports dated January 4, 2002, and June 7, 2004, respectively. The equipment inspections included the combustion turbines, internals and support equipment. All work was carried out closely following the instructions and guidance found in the original equipment manufacturer's design, maintenance and inspection manuals. Acceptance criteria and corrective actions for these activities ensure that equipment is maintained within design specifications.

The Unit I inspection was a Major maintenance inspection. The Major inspection is the most comprehensive inspection that is performed on the combustion turbine units. The interval between Major inspections is based on operating experience with these and similar combustion turbine installations, and factors that affect part life such as fuel type and starting frequency. The purpose of this type of maintenance inspection is to identify equipment degradation, and if degradation is identified the affected component is replaced or refurbished in accordance with manufacturers specifications such that the unit will perform reliably through the next operating interval. This was the first major inspection that was performed on the unit since initial installation in 1988. During the Unit 1 inspection, extensive cracking was found in the exhaust system ductwork and expansion joint. The degradation allowed hot exhaust gasses to escape but did not prevent the combustion turbine from operating. The damaged components were weld repaired. Cracking was also identified in some turbine casing sections, which were also repaired prior to loss of component function. The stainless steel inlet ductwork was inspected with no deficiencies noted. The generator heat exchangers were opened, cleaned and inspected, and no deficiencies were note with the copper tubes. Maintenance personnel stated that the tubes were found in good condition.

The Unit 2 inspection was a fuel nozzle and combustion section inspection. The Unit 2 inspection found the inlet filter housing to be in good condition, with no visual defects. Exhaust ductwork was also inspected. No serious defects were found. One channel section was found with missing nuts, and new nuts were installed. Repair of identified cracks was deferred to the next major overhaul outage.

Unit 2 began a major outage inspection in October 2005. During the outage, with many components disassembled, components were visually inspected for signs of age related degradation. The internal surfaces of disassembled exhaust system ductwork and turbine casing sections were observed. The exhaust system components were cracked and were being replaced. The casing also had cracks that were being repaired. The exhaust system and casing cracks had not prevented combustion turbine operation prior to the scheduled outage. Minor exhaust system and casing leaks do not prevent the combustion turbine from performing its intended function of providing alternate AC power to Oyster Creek during a station blackout event. The glycol cooling water heat exchanger tubes and fins at the mechanical draft cooling tower were visually inspected and did not show signs of significant corrosion. External surfaces of elastomer flexible connections were inspected and did not appear cracked or deteriorated.

The operating experience with the Forked River combustion turbines includes a significant number of past inspection activities of components in the scope of this Periodic Inspection Program. The documented inspection results provide confirmation that existing environmental conditions are not causing material degradation that could result in a loss of component intended functions. Past inspections have been performed at a frequency as long at 16 years, with the units performing reliably between inspections. Implementation of this new program will assure that these inspections are continued on a more conservative frequency of 10 years, providing assurance that the aging effects will be adequately managed for the period of extended operation.

The project team reviewed the operating experience provided in the OCGS LRA, and interviewed the applicant's technical staff to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant’s Periodic Inspection Program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

A7.3.0.3.3.2.2 <u>UFSAR Supplement</u>

The applicant provided its UFSAR Supplement for the Periodic Inspection Program – FRCT program in their response to NRC RAI 2.5.1.19-1 which stated that the aging management program is a new program that will consist of periodic inspections of selected components to verify the integrity of the system and confirm the absence of identified aging effects. Inspections will be scheduled to coincide with major combustion turbine maintenance inspections, when the subject components are made accessible. These inspections will be performed on a frequency not to exceed once every 10 years. The purpose of the inspection is to determine if a specified aging effect is occurring. If the aging effect is occurring, an evaluation will be performed to determine the effect it will have on the ability of affected components to perform their intended functions for the period of extended operation, and appropriate corrective action is taken. Inspection methods may include visual examination, surface or volumetric examinations. Acceptance criteria are in accordance with manufacturers guidelines, applicable codes, and standards. When inspection results fail to meet established acceptance criteria, an evaluation will be conducted to identify actions or measures necessary to provide assurance that the component intended function is maintained during the period of extended operation.

The initial inspections associated with this program will be performed at the next major inspection outage for each unit. Based on an inspection frequency of 10 years, the next inspection for CT Unit 1 will be performed by May 2014, and the next inspection for CT Unit 2 will be performed by November 2015.

The project team also reviewed the applicant’s updated license renewal commitment list in Appendix A of the supplemental response to RAI 2.5.1.19-1, and confirmed that this program is identified as a new program that will be implemented prior to the period of extended operation as item 60 of the commitments.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical staff, the project team determined that the applicant’s Periodic Inspection Program – FRCT program will adequately manage the aging effects that are identified in the OCGS LRA for which this AMP is credited.

The project team reviewed the UFSAR Supplement, found that it was consistent with the GALL Report, and determined that it provides an adequate summary description of the program, as identified in the SRP-LR UFSAR Supplement table and as required by 10 CFR 54.21(d).

A7.3.0.3.3.2.3 Conclusion

On the basis of its audit and review of the applicant's program, the project team found that the applicant has demonstrated that the effects of aging will be adequately managed.

On the basis of its review of the UFSAR Supplement for this program, the project team also found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

A7.3.1 Aging Management of Electrical Systems

This section of the audit and review report documents the project team's review and evaluation of the FRCT, radio communications system, and Met tower aging management review (AMR) results for the aging management of the electrical components and component groups associated with these systems.

A7.3.1.1 Summary of Technical Information in the Application

In its response to Appendix C to RAI 2.5.1.19-1, the applicant provided the results of its AMRs for the FRCT electrical system components and component groups.

In its response to Appendix C to RAI 2.5.1.19-1, the applicant provided the results of its AMRs for the FRCT electrical system components and component groups.

In Table 3.6.1A, the applicant provided a summary comparison of its AMR line items with the AMR line items evaluated in the GALL Report for the electrical system components and component groups. For each component type in Table 3.6.1A, the applicant also identified those AMRs that are consistent with the GALL Report, those for which the GALL Report recommends further evaluation, and those AMRs that are not addressed in the GALL Report, together with the basis for their exclusion.

In Table 3.6.2.1.2A, the applicant provided the AMR results for electrical component types associated with the SBO system. Specifically, the information for each component type included the intended function, material, environment, aging effect requiring management (AERM), AMPs, the GALL Report Volume 2 item, cross-reference to Table 3.6.1A (Table 1), and generic and plant-specific notes related to consistency with the GALL Report.

The applicant's AMRs incorporated applicable operating experience in determining the AERMs. These reviews included the evaluation of both plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

A7.3.1.2 Project Team Evaluation

The project team reviewed the applicant’s response to Appendix C to RAI 2.5.1.19-1 to determine if the applicant provided sufficient information to demonstrate that the effects of aging for the FRCT electrical system components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The project team reviewed certain identified AMR line items to confirm the applicant’s claim that these AMR line items were consistent with the GALL Report. The project team did not repeat its review of the matters described in the GALL Report. However, the project team did verify that the material presented in the response to Appendix C to RAI 2.5.1.19-1 was applicable and that the applicant had identified the appropriate GALL Report AMR line items. The project team’s audit evaluation is documented in Section A7.3.1.2.1 of this Attachment 7 to the audit and review report. In addition, the project team’s evaluations of the AMPs are documented in Section A7.3.0.3 of this Attachment 7 to the audit and review report.

The project team reviewed those selected AMR line items for which further evaluation is recommended by the GALL Report. The project team confirmed that the applicant’s further evaluations were in accordance with the acceptance criteria in the SRP-LR. The project team’s audit evaluation is documented in Section A7.3.1.2.2 of this Attachment 7 to the audit and review report.

The project team also reviewed the remaining AMR line items that were not consistent with or not addressed in the GALL Report. The project team’s audit evaluation is documented in Section A7.3.1.2.3 of this Attachment 7 to the audit and review report.

Finally, the project team reviewed the AMP summary descriptions in the UFSAR Supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the auxiliary systems.

Table A7.3.1-1 below provides a summary of the project team’s evaluation of the components, aging effects/aging mechanisms, and AMPs listed in the applicant’s response to Appendix C to RAI 2.5.1.19-1 that are addressed in the GALL Report. It also includes the section of this Attachment 7 to the audit and review report in which the project team’s evaluation is documented.

Table A7.3.1-1 Evaluation for FRCT Electrical System Components in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Project Team Evaluation
Electrical Equipment Subject to 10 CFR 50.49 EQ Requirements (Item 3.6.1-1)	Degradation due to various aging mechanisms	Environmental Qualification of Electric Components	Not applicable	Not applicable (No EQ components in electrical system)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Project Team Evaluation
Electrical Cables, Connections and Fuse Holders (Insulation) Not Subject to 10 CFR 50.49 EQ Requirements (Item 3.6.1-2)	Reduced insulation resistance and electrical failure due to various physical, thermal, radiolytic, photolytic, and chemical mechanisms	Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements	B.1.37	Consistent with GALL (See Audit Report Section A7.3.1.2.1)
Conductor Insulation for Electrical Cables and Connections Used in Instrumentation Circuits Not Subject to 10 CFR 50.49 EQ Requirements that are Sensitive to Reduction in Conductor Insulation Resistance (Item 3.6.1-3)	Reduced insulation resistance and electrical failure due to various physical, thermal, radiolytic, photolytic, and chemical mechanisms	Electrical Cables And Connections Used In Instrumentation Circuits Not Subject To 10 CFR 50.49 EQ Requirements	Not applicable	Not applicable
Conductor Insulation for Inaccessible Medium Voltage (2 kv to 35 kv) Cables (e.g., installed in conduit or direct buried) Not Subject to 10 CFR 50.49 EQ Requirements (Item 3.6.1-4)	Localized damage and breakdown of insulation leading to electrical failure due to moisture intrusion, water trees	Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements	B.1.36	Consistent with GALL (See Audit Report Section A7.3.1.2.1)
Fuse Holders (Not Part of a Larger Assembly): Fuse Holders – Metallic Clamp (Item 3.6.1-6)	Fatigue due to ohmic heating, thermal cycling, electrical transients, frequent manipulation, vibration, chemical contamination, corrosion, and oxidation	Fuse Holders	None	NUREG-1801 aging effect not applicable to Oyster Creek (See evaluation by DE)
Metal Enclosed Bus - Bus/ Connections (Item 3.6.1-7)	Loosening of bolted connections due to thermal cycling and ohmic heating	Metal Enclosed Bus	B.1.37	Consistent with GALL (See Audit Report Section A7.3.1.2.1)
Metal Enclosed Bus - Insulation/ Insulators (Item 3.6.1-8)	Reduced insulation resistance and electrical failure due	Metal Enclosed Bus	B.1.37	Consistent with GALL (See Audit Report Section

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Project Team Evaluation
	to various physical, thermal, radiolytic, photolytic, and chemical mechanisms			A7.3.1.2.1)
Metal Enclosed Bus - Enclosure Assemblies (Item 3.6.1-9)	Loss of material due to general corrosion	Structures Monitoring Program	B.1.31	Consistent with GALL (See Audit Report Section A7.3.1.2.1)
Metal Enclosed Bus - Enclosure Assemblies (Item 3.6.1-10)	Hardening and loss of strength due to elastomers degradation	Structures Monitoring Program	B.1.31	Consistent with GALL (See Audit Report Section A7.3.1.2.1)
High Voltage Insulators (Item 3.6.1-11)	Degradation of insulation quality due to presence of any salt deposits and surface contamination; Loss of material caused by mechanical wear due to wind blowing on transmission conductors	A plant-specific AMP is to be evaluated	None	NUREG-1801 aging effect is not applicable to Oyster Creek (See evaluation by DE)
Transmission Conductors and Connections; Switchyard Bus and Connections (Item 3.6.1-12)	Loss of material due to wind induced abrasion and fatigue; loss of conductor strength due to corrosion; increased resistance of connection due to oxidation or loss of preload	A plant-specific AMP is to be evaluated	None	NUREG-1801 aging effect not applicable to Oyster Creek (See evaluation by DE)
Cable Connections - Metallic Parts (Item 3.6.1-13)	Loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation	Electrical Cable Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements	None	NUREG-1801 aging effect not applicable to Oyster Creek (See evaluation by DE)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Project Team Evaluation
Fuse Holders (Not Part of a Larger Assembly) Insulation Material (Item 3.6.1-14)	None	None	None	N/A

A7.3.1.2.1 *AMR Results That Are Consistent with The GALL Report*

Summary of Information in the Application

For aging management evaluations that the applicant stated are consistent with the GALL Report, the project team conducted its audit and review to determine if the applicant's reference to the GALL Report in the OCGS LRA is acceptable.

In the applicant's supplemental response to Appendix C to RAI 2.5.1.19-1, the applicant identified the materials, environments, and aging effects requiring management. The applicant identified the following programs that manage the aging effects related to the FRCT electrical systems:

- Structures Monitoring Program (B.1.31)
- Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements (B.1.36)
- Periodic Monitoring of Combustion Turbine Power Plant – Electrical (B.1.37)

Project Team Evaluation

The project team reviewed its assigned FRCT AMR line items to determine that the applicant (1) provided a brief description of the system, components, materials, and environment, (2) stated that the applicable aging effects have been reviewed and are evaluated in the GALL Report, and (3) identified those aging effects for the FRCT electrical system components that are subject to an AMR.

Conclusion

The project team has evaluated the applicant's claim of consistency with the GALL Report. The project team also has reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the project team found that the AMR results that the applicant claimed to be consistent with the GALL Report are consistent with the AMRs in the GALL Report.

A7.3.1.2.2 *AMR Results For Which Further Evaluation Is Recommended By The GALL Report*

Section A7.3.1.2.2 is reviewed by NRR/DE staff

A7.3.1.2.3 *AMR Results That Are Not Consistent With The GALL Report Or Not Addressed In The GALL Report*

Section A7.3.1.2.3 is reviewed by NRR/DE staff

A7.3.2 Aging Management of Mechanical Systems

This section of the audit and review report documents the project team's review and evaluation of the FRCT and radio communications systems aging management review (AMR) results for the aging management of the mechanical components and component groups associated with these systems.

A7.3.2.1 Summary of Technical Information in the Application

In its supplemental response to RAI 2.5.1.19-1, and its response to RAI 2.5.1.15-1, the applicant provided the results of its AMRs for the FRCT and radio communications systems mechanical system components and component groups, respectively.

In Table 3.6.1B, ?Summary of Aging Management Evaluations for the Station Blackout System-Mechanical," and Table 3.6.1D, ?Summary of Aging Management Evaluations," the applicant provided a summary comparison of its AMR line-items with the AMR line-items evaluated in the GALL Report for the mechanical system components and component groups. The applicant also identified, for each component type, those AMRs that are consistent with the GALL Report, and those for which the GALL Report recommends further evaluation.

In Tables 3.6.2.1.2B and 3.6.2.1.3, the applicant provided the AMR results for mechanical component types associated with the Station Blackout System and the radio communications systems, respectively. Specifically, the information for each component type included the intended function, material, environment, aging effect requiring management, AMPs, the GALL Report Volume 2 item, cross reference to the Table 3.6.1B or 3.6.1D (Table 1), and generic and plant-specific notes related to consistency with the GALL Report.

The applicant's AMRs incorporated applicable operating experience in the determination of the aging effects requiring management (AERMs). These reviews included the evaluation of both plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

A7.3.2.2 Project Team Evaluation

The project team reviewed the applicant's supplemental response to RAI 2.5.1.19-1 and its response to RAI 2.5.1.15-1 to determine if the applicant provided sufficient information to demonstrate that the effects of aging for the FRCT and radio communications systems mechanical system components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The project team reviewed all AMR line-items to confirm the applicant's claim that these AMR line-items were consistent with the GALL Report. The project team did not repeat its review of the matters described in the GALL Report. However, the project team did verify that the material presented in the supplemental response to RAI 2.5.1.19-1, and the response to RAI 2.5.1.15-1 was applicable and that the applicant had identified the appropriate GALL Report AMR line-items. The project team's audit evaluation is documented in Section A7.3.2.2.1 of this Attachment 7 to the audit and review report. In addition, the project team's evaluations of the AMPs are documented in Section A7.3.0.3 of this Attachment 7 to the audit and review report.

The project team reviewed those selected AMR line-items for which further evaluation is recommended by the GALL Report. The project team confirmed that the applicant's further evaluations were in accordance with the acceptance criteria in the SRP-LR. The project team's audit evaluation is documented in Section A7.3.2.2.2 of this Attachment 7 to the audit and review report.

The project team also reviewed the remaining AMR line-items that were not consistent with or not addressed in the GALL Report. The project team's audit evaluation is documented in Section A7.3.2.2.3 of this Attachment 7 to the audit and review report.

Finally, the project team reviewed the AMP summary descriptions in the UFSAR Supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the auxiliary systems.

Table A7.3.2-1 below provides a summary of the project team's evaluation of the components, aging effects/aging mechanisms, and AMPs listed in the applicant's supplemental responses to RAI 2.5.1.19-1 and RAI 2.5.1.15-1 that are addressed in the GALL Report. It also includes the section of this Attachment 7 to the audit and review report in which the project team's evaluation is documented.

Table A7.3.2-1 Evaluation for FRCT and Radio Communications Systems Mechanical System Components in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Project Team Evaluation
Stainless steel and copper alloy piping, piping components, and piping elements exposed to lubricating oil (Item 3.2.1-6)	Loss of material due to pitting and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Lubricating Oil Analysis – FRCT and One-Time Inspection – FRCT	Consistent with GALL, which recommends further evaluation (See Audit Report Attachment 7, Section A7.3.2.2.2.1)
Steel, stainless steel, and copper alloy heat exchanger tubes exposed to lubricating oil (Item 3.2.1-9)	Reduction of heat transfer due to fouling	Lubricating Oil Analysis and One-Time Inspection	Lubricating Oil Analysis – FRCT and One-Time Inspection – FRCT	Consistent with GALL, which recommends further evaluation (See Audit Report Section A7.3.2.2.2.2)
Copper alloy > 15% Zn piping, piping components, piping elements, and heat exchanger components exposed to closed cycle cooling water (Item 3.2.1-41)	Loss of material due to selective leaching	Selective Leaching of Materials	Selective Leaching of Materials – FRCT	Consistent with GALL (See Audit Report, Attachment 7, Section A7.3.2.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Project Team Evaluation
Aluminum piping, piping components, and piping elements exposed to air – indoor uncontrolled (internal/external) (Item 3.2.1-50)	None	None	None	Consistent with GALL (See Audit Report, Attachment 7, Section A7.3.2.2.3.1)
Stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust (Item 3.3.1-6)	Cracking due to stress corrosion cracking	A plant-specific AMP is to be evaluated.	Periodic Inspection – FRCT	Consistent with GALL, which recommends further evaluation (See Audit Report Attachment 7, Section A7.3.2.2.2.3)
Elastomer seals and components exposed to air – indoor uncontrolled (internal/external) (Item 3.3.1-11)	Hardening and loss of strength due to elastomer degradation	A plant-specific AMP is to be evaluated	Periodic Inspection – FRCT	Consistent with GALL, which recommends further evaluation (See Audit Report Attachment 7, Section A7.3.2.2.2.4)
Steel piping, piping component, and piping elements exposed to lubricating oil (Item 3.3.1-14)	Loss of material due to general, pitting, and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Lubricating Oil Analysis – FRCT and One-Time Inspection – FRCT	Consistent with GALL, which recommends further evaluation (See Audit Report Section A7.3.2.2.2.5.1)
Stainless steel and steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust (Item 3.3.1-18)	Loss of material/general (steel only), pitting and crevice corrosion	A plant-specific AMP is to be evaluated	Periodic Inspection – FRCT	Consistent with GALL, which recommends further evaluation (See Audit Report Attachment 7, Section A7.3.2.2.2.5.2)
Steel (with or without coating or wrapping) piping, piping components, and piping elements exposed to soil (Item 3.3.1-19)	Loss of material due to general, pitting, crevice, and MIC	Buried Piping and Tanks Surveillance or Buried Piping and Tanks Inspection	Buried Piping Inspection – FRCT and Aboveground Steel Tanks – FRCT	Consistent with GALL, which recommends further evaluation (See Audit Report Section A7.3.2.2.2.6)
Steel piping, piping components, piping elements, and tanks exposed to fuel oil (Item 3.3.1-20)	Loss of material due to general, pitting, crevice, and MIC, and fouling	Fuel Oil Chemistry and One-Time Inspection	Fuel Oil Chemistry – FRCT and One-Time Inspection – FRCT	Consistent with GALL, which recommends further evaluation (See Audit Report Section A7.3.2.2.2.7.1)
Steel heat exchanger components exposed to lubricating oil (Item 3.3.1-21)	Loss of material due to general, pitting, crevice, and MIC, and fouling	Lubricating Oil Analysis and One-Time Inspection	Lubricating Oil Analysis – FRCTand One-Time Inspection – FRCT	Consistent with GALL, which recommends further evaluation (See Audit Report Section A7.3.2.2.2.7.2)
Copper alloy HVAC piping, piping components, piping	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be	Periodic Inspection – FRCT	Consistent with GALL, which recommends further evaluation

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Project Team Evaluation
elements exposed to condensation (external) (Item 3.3.1-25)		evaluated.		(See Audit Report Section A7.3.2.2.2.8)
Stainless steel, aluminum and copper alloy piping, piping components, and piping elements exposed to fuel oil (Item 3.3.1-32)	Loss of material due to pitting, crevice, and MIC	Fuel Oil Chemistry and One-Time Inspection	Fuel Oil Chemistry – FRCT and One-Time Inspection – FRCT	Consistent with GALL (aluminum and copper alloy), which recommends further evaluation (See Audit Report Section A7.3.2.2.2.9.1)
Stainless steel piping, piping components, and piping elements exposed to lubricating oil (Item 3.3.1-33)	Loss of material due to pitting, crevice, and MIC	Lubricating Oil Analysis and One-Time Inspection	Lubricating Oil Analysis – FRCT and One-Time Inspection – FRCT	Consistent with GALL, which recommends further evaluation (See Audit Report Section A7.3.2.2.2.9.2)
Steel closure bolting exposed to air – indoor uncontrolled (external) (Item 3.3.1-35)	Loss of material due to general, pitting and crevice corrosion, loss of preload due to stress relaxation	Bolting Integrity	Structures Monitoring (B.1.31)	Acceptable since the OCGS structures monitoring program is consistent with the recommendations in the GALL bolting integrity program for this component group/aging effect combination (See Audit Report Section A7.3.2.2.1.3)
Steel bolting exposed to air – outdoor (external) (Item 3.3.1-36)	Loss of material due to general, pitting and crevice corrosion	Bolting Integrity	Structures Monitoring (B.1.31)	Acceptable since the OCGS structures monitoring program is consistent with the recommendations in the GALL bolting integrity program for this component group/aging effect combination (See Audit Report Section A7.3.2.2.1.3)
Steel tanks in diesel fuel oil system exposed to air – outdoor (external) (Item 3.3.1-40)	Loss of material due to general, pitting, and crevice corrosion	Aboveground Steel Tanks	Aboveground Steel Tanks – FRCT	Consistent with GALL (See Audit Report Section A7.3.2.2.1)
Steel bolting and closure bolting exposed to air – indoor uncontrolled (external) or air – outdoor (External) (Item 3.3.1-43)	Loss of material due to general, pitting, and crevice corrosion	Bolting Integrity	Bolting Integrity – FRCT	Consistent with GALL (See Audit Report Section A7.3.2.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Project Team Evaluation
Steel closure bolting exposed to air – indoor uncontrolled (external) (Item 3.3.1-45)	Loss of preload due to thermal effects, gasket creep, and self-loosening	Bolting Integrity	Bolting Integrity – FRCT	Consistent with GALL (See Audit Report Section A7.3.2.2.1)
Steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to closed cycle cooling water (Item 3.3.1-47)	Loss of material due to general, pitting, and crevice corrosion	Closed-Cycle Cooling Water System	Closed-Cycle Cooling Water – FRCT	Consistent with GALL (See Audit Report Section A7.3.2.2.1)
Steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to closed cycle cooling water (Item 3.3.1-48)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	Closed-Cycle Cooling Water – FRCT	Consistent with GALL (See Audit Report Section A7.3.2.2.1)
Stainless steel piping, piping components, and piping elements exposed to closed cycle cooling water (Item 3.3.1-50)	Loss of material due to pitting and crevice corrosion	Closed-Cycle Cooling Water System	Closed-Cycle Cooling Water – FRCT	Consistent with GALL (See Audit Report Section A7.3.2.2.1)
Copper alloy piping, piping components, piping elements, and heat exchanger components exposed to closed cycle cooling water (Item 3.3.1-51)	Loss of material due to pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	Closed-Cycle Cooling Water – FRCT	Consistent with GALL (See Audit Report Section A7.3.2.2.1)
Steel, stainless steel, and copper alloy heat exchanger tubes exposed to closed cycle cooling water (Item 3.3.1-52)	Reduction of heat transfer due to fouling	Closed-Cycle Cooling Water System	Closed-Cycle Cooling Water – FRCT	Consistent with GALL (See Audit Report Section A7.3.2.2.1)
Steel ducting closure bolting exposed to air – indoor uncontrolled (external) (Item 3.3.1-55)	Loss of material due to general corrosion	External Surfaces Monitoring	Structures Monitoring	Acceptable since the structures monitoring program is consistent with the external surfaces monitoring program for this component group/ aging effect combination (See Audit Report Section A7.3.2.2.1.2)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Project Team Evaluation
Steel HVAC ducting and components external surfaces exposed to air – indoor uncontrolled (external) (Item 3.3.1-56)	Loss of material due to general corrosion	External Surfaces Monitoring	Structures Monitoring	Acceptable since the structures monitoring program is consistent with the external surfaces monitoring program for this component group/ aging effect combination (See Audit Report Section A7.3.2.2.1.2)
Steel external surfaces exposed to air – indoor uncontrolled (external), air – outdoor (external), and condensation (external) (Item 3.3.1-58)	Loss of material due to general corrosion	External Surfaces Monitoring	Structures Monitoring	Acceptable since the structures monitoring program is consistent with the external surfaces monitoring program for this component group/ aging effect combination (See Audit Report Section A7.3.2.2.1.2)
Steel piping, piping components, and piping elements exposed to air – outdoor (external) (Item 3.3.1-60)	Loss of material due to general, pitting, and crevice corrosion	External Surfaces Monitoring	Structures Monitoring	Acceptable since the structures monitoring program is consistent with the external surfaces monitoring program for this component group/ aging effect combination (See Audit Report Section A7.3.2.2.1.2)
Elastomer fire barrier penetration seals exposed to air -outdoor or air – indoor uncontrolled (3.3.1-61)	Increased hardness, shrinkage and loss of strength due to weathering	Fire Protection	Structures Monitoring	Acceptable since the OCGS structures monitoring program is consistent with the GALL fire protection program for this component group/ aging effect combination (See Audit Report Section A7.3.2.2.1.1)
Steel HVAC ducting and components internal surfaces exposed to condensation (Internal) (Item 3.3.1-72)	Loss of material due to general, pitting, crevice, and (for drip pans and drain lines) MIC	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL (See Audit Report Section A7.3.2.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Project Team Evaluation
Galvanized steel piping, piping components, and piping elements exposed to air – indoor uncontrolled (Item 3.3.1-74)	None	None	None	Consistent with GALL (See Audit Report Section A7.3.2.2.3.1)
Steel and stainless steel piping, piping components, and piping elements in concrete (Item 3.3.1-78)	None	None	None	Consistent with GALL (See Audit Report Section A7.3.2.2.3.1)
Copper alloy > 15% Zn piping, piping components, piping elements, and heat exchanger components exposed to raw water, treated water, or closed cycle cooling water (Item 3.3.1-84)	Loss of material due to selective leaching	Selective Leaching of Materials	Selective Leaching of Materials – FRCT	Consistent with GALL (See Audit Report Section A7.3.2.2.1)
Galvanized steel piping, piping components, and piping elements exposed to air -indoor uncontrolled (3.3.1-92)	None	None	None	Consistent with GALL (See Audit Report Section A7.3.2.2.3.1)
Glass piping elements exposed to air, air – indoor uncontrolled (external), fuel oil, lubricating oil, raw water, treated water, and treated borated water (Item 3.3.1-93)	None	None	None	Consistent with GALL (See Audit Report Section A7.3.2.2.3.1)
Stainless steel and nickel alloy piping, piping components, and piping elements exposed to air – indoor uncontrolled (external) (Item 3.3.1-94)	None	None	None	Consistent with GALL (See Audit Report Section A7.3.2.2.3.1)
Steel and stainless steel piping, piping components, and piping elements in concrete (Item 3.3.1-96)	None	None	None	Acceptable – No AMP is needed since no aging effect is identified for this component group (See Audit Report Section A7.3.2.2.3.1)
Steel, stainless steel, aluminum, and copper alloy piping, piping	None	None	None	Acceptable – No AMP is needed since no aging effect is

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Project Team Evaluation
components, and piping elements exposed to gas (Item 3.3.1-97)				identified for this component group.. (See Audit Report Section A7.3.2.2.3.1)
Buried steel piping, piping components, piping elements, and tanks (with or without coating or wrapping) exposed to soil (Item 3.4.1-11)	Loss of material due to general, pitting, crevice, and MIC	Buried Piping and Tanks Surveillance or Buried Piping and Tanks Inspection	Buried Piping Inspection (B.1.26)	Consistent with GALL, which recommends further evaluation (See Audit Report Section. A7.3.2.2.2.6.1)
Steel heat exchanger components exposed to closed cycle cooling water (Item 3.4.1-24)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	Closed-Cycle Cooling Water – FRCT	Consistent with GALL (See Audit Report Section A7.3.2.2.1)
Groups B2, and B4: galvanized steel, aluminum, stainless steel support members; welds; bolted connections; support anchorage to building structure (Item 3.5.1-50)	Loss of material due to pitting and crevice corrosion	Structures Monitoring Program	Structures Monitoring Program	Consistent with GALL (See Audit Report Section A7.3.2.2.1)

A7.3.2.2.1 *AMR Results That Are Consistent with The GALL Report*

<u>Summary of Information in the Application</u>

For aging management evaluations that the applicant stated are consistent with the GALL Report, the project team conducted its audit and review to determine if the applicant's reference to the GALL Report in the OCGS LRA is acceptable.

In the applicant's supplemental response to RAI 2.5.1.19-1, Appendix C, the applicant identified the materials, environments, and aging effects requiring management. The applicant identified the following programs that manage the aging effects related to the FRCT mechanical systems:

- Bolting Integrity – FRCT (B.1.12A)
- Closed-Cycle Cooling Water System – FRCT (B.1.14A)
- Aboveground Steel Tanks – FRCT (B.1.21A)
- Fuel Oil Chemistry – FRCT (B.1.22A)
- One-Time Inspection – FRCT (B.1.24A)
- Selective Leaching of Materials – FRCT (B.1.25A)
- Buried Piping Inspection – FRCT (B.1.26A)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components – FRCT (B.1.38)
- Structures Monitoring Program (B.1.31)
- Lubricating Oil Analysis Program – FRCT (B.1.39)
- Periodic Inspection Program – FRCT (B.2.5A)

Project Team Evaluation

The project team reviewed its assigned FRCT AMR line-items to determine that the applicant (1) provides a brief description of the system, components, materials, and environment; (2) states that the applicable aging effects have been reviewed and are evaluated in the GALL Report; and (3) identifies those aging effects for the FRCt mechanical system components that are subject to an AMR.

A7.3.2.2.1.1 Increased Hardness, Shrinkage, and Loss of Strength Due to Weathering (Met Tower Table 3.6.1D)

In the response to RAI 2.5.1.15-1, Table 3.5.2.1.20 for the Met tower included AMR line items for changes in material properties manifested as hardening and loss of strength due to elastomer degradation for conduit components constructed of elastomers exposed to an outdoor air environment. The applicant proposed to manage this aging effect using the OCGS structures monitoring program (AMP B.1.31). Generic note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report; however, a different aging management program was credited. The GALL Report recommended the fire protection program, AMP XI.M26, to manage this aging effect.

The project team reviewed the applicant's structures monitoring program (AMP B.1.31), and verified that this program includes visual inspections of component external surfaces to detect aging degradation of elastomer components. The project team determined that this AMP is consistent with the recommendations in the GALL fire protection program, and is adequate to detect hardening and loss of strength due to elastomer degradation prior to a loss of intended function to manage this aging effect.

On the basis of its review, the project team found that the applicant appropriately addressed hardening and loss of strength due to elastomer degradation for elastomer components in the Met tower systems.

A7.3.2.2.1.2 Loss of Material Due to General Corrosion (FRCT Table 3.6.1B)

In the response to RAI 2.5.1.19-1, Table 3.6.2.1.2B for the station blackout system included AMR line items for loss of material due to general corrosion for the external surfaces of components constructed of carbon and low alloy steel exposed to indoor air (uncontrolled). The applicant proposed to manage this aging effect using the OCGS structures monitoring program, AMP B.1.31. Generic note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report; however, a different aging management program was credited. The GALL Report recommended the external surfaces monitoring program, AMP XI.M36, to manage this aging effect.

The project team reviewed the applicant's structures monitoring program (AMP B.1.31) and verified that this aging management program included activities that are consistent with GALL AMP XI.M26 to manage the loss of material in components exposed to an indoor air external environment. The project team determined that OCGS AMP B.1.31 will adequately manage the loss of material due to general corrosion for the external surfaces of components constructed of carbon and low alloy steel exposed to indoor air (uncontrolled).

On the basis of its review, the project team found that the applicant appropriately addressed loss of material due to general corrosion for the external surfaces of components constructed of carbon and low alloy steel exposed to indoor air (uncontrolled)in the FRCT systems.

A7.3.2.2.1.3 Loss of Material Due to General, Pitting and Crevice Corrosion and Loss of Preload (FRCT Table 3.6.1C)

In the response to RAI 2.5.1.19-1, Table 3.6.2.1.2C for the station blackout system included AMR line items for loss of material due to general, pitting, and crevice corrosion, and loss of preload for bolting constructed of carbon and low alloy steel and galvanized steel exposed to outdoor or indoor air (uncontrolled). The applicant proposed to manage this aging effect using the OCGS structures monitoring program, AMP B.1.31. Generic note E was cited for these AMR line items, indicating that the material, environment, and aging effect were consistent with the GALL Report; however, a different aging management program was credited. The GALL Report recommended the bolting integrity program, AMP XI.M18, to manage this aging effect.

The project team reviewed the applicant's structures monitoring program (AMP B.1.31) and verified that this aging management program included activities that are consistent with GALL AMP XI.M18 to manage the loss of material and loss of preload in bolting exposed to an outdoor or indoor air external environment. The project team determined that OCGS AMP B.1.31 will adequately manage the loss of material due to general, pitting, and crevice corrosion, and loss of preload for bolting exposed to outdoor or indoor air (uncontrolled).

On the basis of its review, the project team found that the applicant appropriately addressed loss of material due to general, pitting, and crevice corrosion, and loss of preload for bolting in the FRCT systems.

Conclusion

The project team has evaluated the applicant's claim of consistency with the GALL Report. The project team also has reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the project team found that the AMR results, which the applicant claimed to be consistent with the GALL Report, are consistent with the AMRs in the GALL

A7.3.2.2.2 *AMR Results For Which Further Evaluation Is Recommended By The GALL Report*

Summary of Information in the Application

In applicant's supplemental response to RAI 2.5.1.19-1, Appendix C, Table 3.6.1B, the applicant provided further evaluation of aging management as recommended by the GALL Report for the FRCT mechanical system components and component groups. The applicant also provided information concerning how it will manage the related aging effects.

Project Team Evaluation

For some AMR line-items assigned to the project team in Table 3.6.1B of the applicant's supplemental response to RAI 2.5.1.19-1, Appendix C, the GALL Report recommends further evaluation. When further evaluation was recommended, the project team reviewed these further evaluations provided in Table 3.6.1B of the applicant's supplemental response to RAI 2.5.1.19-1,

Appendix C, against the criteria provided in the corresponding section of the SRP-LR. The project team's assessment of these evaluations is documented in this section. These assessments are applicable to each Table 3.6.2.1.2B AMR line-item citing the item in Table 3.6.1B.

A7.3.2.2.2.1 Loss of Material Due to Pitting and Crevice Corrosion

The project team reviewed FRCT Table 3.6.1B, line item 3.2.1-6 against the criteria in SRP-LR Section 3.2.2.2.3.4.

SRP-LR, Section 3.2.2.2.3.4 stated that loss of material from pitting and crevice corrosion could occur for stainless steel and copper alloy piping, piping components, and piping elements exposed to lubricating oil. The existing program relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. However, control of lube oil contaminants may not always have been adequate to preclude corrosion. Therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion is not occurring. The GALL Report recommends further evaluation to verify the effectiveness of the lubricating oil program. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In FRCT Table 3.6.1B, line item 3.2.1-6, the applicant stated that the one-time inspection – FRCT aging management program, B.1.24A, will be used to verify the effectiveness of the Lubricating Oil Analysis Program – FRCT, B.1.39, at managing the loss of material in copper alloy heat exchanger tubes exposed to a lubricating oil environment. The One-Time Inspection – FRCT aging management program includes (a) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience; (b) identification of the inspection locations in the system or component based on the aging effect; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined; and (d) evaluation of the need for follow-up examinations to monitor the progression of aging if age related degradation is found that could jeopardize an intended function before the end of the period of extended operation.

The project team reviewed the applicant's Lubricating Oil Analysis Program – FRCT (AMP B.1.39) and verified that this aging management program included activities that are consistent with the recommendations in GALL AMP XI.M39 to manage loss of material for components exposed to lubricating oil. In addition, the project team reviewed the applicant's One-Time Inspection Program – FRCT (B.1.24A) and verified that this aging management program includes inspections to detect loss of material as a means of verifying the effectiveness of the Lubricating Oil Analysis Program – FRCT. The project team determined that FRCT AMPs B.1.39 and B.1.24A, together, will adequately manage loss of material in copper alloy heat exchanger tubes exposed to a lubricating oil environment.

The project team found that, based on the information discussed above, the applicant has met the criteria of SRP-LR Section 3.2.2.2.3.4 for further evaluation.

A7.3.2.2.2.2 Reduction of Heat Transfer Due to Fouling

The project team reviewed FRCT Table 3.6.1B, line item 3.2.1-9 against the criteria in SRP-LR Section 3.2.2.2.4.1.

SRP-LR, Section 3.2.2.2.4.1 stated that reduction of heat transfer due to fouling could occur for steel, stainless steel, and copper alloy heat exchanger tubes exposed to lubricating oil. The existing AMP relies on monitoring and control of lube oil chemistry to mitigate reduction of heat transfer due to fouling. However, control of lube oil chemistry may not always have been adequate to preclude fouling. Therefore, the effectiveness of lube oil chemistry control should be verified to ensure that fouling is not occurring. The GALL Report recommends further evaluation of programs to verify the effectiveness of lube oil chemistry control. A one-time inspection of select components at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or an aging effect is progressing very slowly such that the component's intended function will be maintained during the period of extended operation.

In FRCT Table 3.6.1B, line item 3.2.1-9, the applicant stated that the one-time inspection – FRCT aging management program, B.1.24A, will be used to verify the effectiveness of the Lubricating Oil Analysis Program – FRCT, B.1.39, at managing the reduction of heat transfer in copper alloy heat exchanger tubes and fins exposed to a lubricating oil environment. The One-Time Inspection – FRCT aging management program includes (a) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience; (b) identification of the inspection locations in the system or component based on the aging effect; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined; and (d) evaluation of the need for follow-up examinations to monitor the progression of aging if age related degradation is found that could jeopardize an intended function before the end of the period of extended operation.

The project team reviewed the applicant's Lubricating Oil Analysis Program – FRCT (AMP B.1.39) and verified that this aging management program included activities that are consistent with the recommendations in GALL AMP XI.M39 to manage the reduction of heat transfer for components exposed to lubricating oil. In addition, the project team reviewed the applicant's One-Time Inspection Program – FRCT (B.1.24A) and verified that this aging management program includes inspections to detect fouling as a means of verifying the effectiveness of the Lubricating Oil Analysis Program – FRCT. The project team determined that FRCT AMPs B.1.39 and B.1.24A, together, will adequately manage the reduction of heat transfer in copper alloy heat exchanger tubes and fins exposed to a lubricating oil environment

The project team found that, based on the information discussed above, the applicant has met the criteria of SRP-LR Section 3.2.2.2.4.1 for further evaluation.

A7.3.2.2.2.3 Cracking Due to Stress Corrosion Cracking

The project team reviewed FRCT Table 3.6.1B, line item 3.3.1-6 against the criteria in SRP-LR Section 3.3.2.2.3.3.

SRP-LR Section 3.3.2.2.3.3 stated that cracking due to SCC could occur in stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust. The GALL Report recommended further evaluation of a plant-specific aging management program to ensure that these aging effects are adequately managed.

In FRCT Table 3.6.1B, line item 3.3.1-6, the applicant stated that the Periodic Inspection Program – FRCT, B.2.5A, will be used to manage cracking in stainless steel combustion turbine exhaust components exposed to a combustion turbine exhaust gas environment. The Periodic Inspection Program – FRCT will address systems in the scope of license renewal that require periodic monitoring of aging effects, and are not covered by other existing periodic monitoring programs. Activities will consist of a periodic inspection of selected systems and components to verify integrity and confirm the absence of identified aging effects. The inspections will be condition monitoring examinations, intended to assure that existing environmental conditions are not causing material degradation that could result in a loss of system intended functions.

The project team reviewed the applicant's Periodic Inspection Program – FRCT (AMP B.2.5A) and verified that this aging management program included activities that are adequate to manage cracking in stainless steel combustion turbine exhaust components. The project team determined that FRCT AMP B.2.5A will adequately manage cracking in stainless steel combustion turbine exhaust components exposed to a combustion turbine exhaust gas environment.

The project team found that, based on the information discussed above, the applicant has met the criteria of SRP-LR Section 3.3.2.2.3.3 for further evaluation.

A7.3.2.2.2.4 Hardening and Loss of Strength Due to Elastomer Degradation

The project team reviewed FRCT Table 3.6.1B, line item 3.3.1-11 against the criteria in SRP-LR Section 3.3.2.2.5.1.

SRP-LR Section 3.3.2.2.5.1 stated that hardening and loss of strength due to elastomer degradation could occur in elastomer seals and components of heating and ventilation systems exposed to air – indoor uncontrolled (internal/external). The GALL Report recommended further evaluation of a plant-specific aging management program to ensure that these aging effects are adequately managed.

In FRCT Table 3.6.1B, line item 3.3.1-11, the applicant addressed hardening and loss of strength of elastomer seals and components due to elastomer degradation. The applicant stated that the Periodic Inspection Program – FRCT, B.2.5A, will be used to manage the change in material properties in elastomer flexible connections exposed to an indoor air (internal) environment. The Periodic Inspection Program – FRCT will address systems in the scope of license renewal that require periodic monitoring of aging effects, and are not covered by other existing periodic monitoring programs. Activities will consist of a periodic inspection of selected systems and components to verify integrity and confirm the absence of identified aging effects. The inspections will be condition monitoring examinations, intended to assure that existing environmental conditions are not causing material degradation that could result in a loss of system intended functions.

The project team reviewed the applicant's Periodic Inspection Program – FRCT (AMP B.2.5A) and verified that this aging management program included activities that are adequate to manage the change in material properties in elastomer flexible connections . The project team determined that FRCT AMP B.2.5A will adequately manage the change in material properties in elastomer flexible connections exposed to an indoor air (internal) environment.

The project team found that, based on the information discussed above, the applicant has met the criteria of SRP-LR Section 3.3.2.2.5.1 for further evaluation.

A7.3.2.2.2.5 Loss of Material Due to General, Pitting, and Crevice Corrosion

A7.3.2.2.2.5.1 Loss of Material Due to General, Pitting, and Crevice Corrosion [Item 1]

The project team reviewed FRCT Table 3.6.1B, line item 3.3.1-14 against the criteria in SRP-LR Section 3.3.2.2.7.1.

SRP-LR Section 3.3.2.2.7.1 stated that loss of material due to general, pitting, and crevice corrosion could occur in steel piping, piping components, and piping elements, including the tubing, valves, and tanks in the reactor coolant pump oil collection system, exposed to lubricating oil (as part of the fire protection system). The existing aging management program relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. However, control of lube oil contaminants may not always have been adequate to preclude corrosion. Therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion is not occurring. The GALL Report recommended further evaluation of programs to manage corrosion to verify the effectiveness of the lubricating oil program. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In FRCT Table 3.6.1B, line item 3.3.1-14, the applicant addressed loss of material of steel piping, piping components, and piping elements due to general, pitting, and crevice corrosion. The applicant stated that the one-time inspection – FRCT aging management program, B.1.24A, will be used to verify the effectiveness of the Lubricating Oil Analysis Program – FRCT, B.1.39, at managing the loss of material in carbon steel and cast iron piping, piping components, piping elements, and tanks exposed to a lubricating oil environment. The One-Time Inspection – FRCT aging management program includes (a) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience; (b) identification of the inspection locations in the system or component based on the aging effect; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined; and (d) evaluation of the need for follow-up examinations to monitor the progression of aging if age related degradation is found that could jeopardize an intended function before the end of the period of extended operation.

The project team reviewed the applicant's Lubricating Oil Analysis Program – FRCT (AMP B.1.39) and verified that this aging management program included activities that are consistent with the recommendations in GALL AMP XI.M39 to manage loss of material for components exposed to lubricating oil. In addition, the project team reviewed the applicant's One-Time Inspection Program – FRCT (B.1.24A) and verified that this aging management program includes inspections to detect loss of material as a means of verifying the effectiveness of the Lubricating Oil Analysis Program – FRCT. The project team determined that FRCT AMPs B.1.39 and B.1.24A, together, will adequately manage loss of material in carbon steel and cast iron piping, piping components, piping elements, and tanks exposed to a lubricating oil environment.

The project team found that, based on the information discussed above, the applicant has met the criteria of SRP-LR Section 3.3.2.2.7.1 for further evaluation.

A7.3.2.2.2.5.2 Loss of Material Due to General, Pitting, and Crevice Corrosion [Item 2]

The project team reviewed FRCT Table 3.6.1B, line item 3.3.1-18 against the criteria in SRP-LR Section 3.3.2.2.7.3.

SRP-LR Section 3.3.2.2.7.3 stated that loss of material due to general (steel only) pitting and crevice corrosion could occur for steel and stainless steel diesel exhaust piping, piping components, and piping elements exposed to diesel exhaust. The GALL Report recommended further evaluation of a plant-specific aging management program to ensure that these aging effects are adequately managed.

In FRCT Table 3.6.1B, line item 3.3.1-18, the applicant addressed loss of material of carbon steel and stainless steel combustion turbine casing and exhaust components, and carbon steel diesel exhaust components, due to general, pitting, and crevice corrosion. The applicant stated that the Periodic Inspection Program – FRCT, B.2.5A, will be used to manage the loss of material in carbon steel and stainless steel combustion turbine casing and exhaust components exposed to a combustion turbine exhaust gas environment. The Periodic Inspection Program – FRCT will address systems in the scope of license renewal that require periodic monitoring of aging effects, and are not covered by other existing periodic monitoring programs. Activities will consist of a periodic inspection of selected systems and components to verify integrity and confirm the absence of identified aging effects. The inspections will be condition monitoring examinations, intended to assure that existing environmental conditions are not causing material degradation that could result in a loss of system intended functions.

The applicant further stated that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components – FRCT, B.1.38, will be used to manage the loss of material in carbon steel diesel exhaust components exposed to a diesel exhaust environment. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components – FRCT, B.1.38, will include visual inspections of the internal surfaces of the combustion turbine starting diesel muffler and exhaust piping. Internal inspections will be performed during scheduled maintenance activities when the surfaces are made accessible for visual inspection. The program includes visual inspections to assure that existing environmental conditions are not causing material degradation that could result in a loss of component intended functions.

The project team reviewed the applicant's Periodic Inspection Program – FRCT (AMP B.2.5A) and verified that this aging management program included activities that are adequate to manage the loss of material of carbon steel and stainless steel combustion turbine casing and exhaust components. In addition, the project team reviewed the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components – FRCT (AMP B.1.38) and verified that this aging management program included activities that are adequate to manage the loss of material in carbon steel diesel exhaust components. The project team determined that FRCT AMPs B.2.5A and B.1.38 will adequately manage the loss of material of carbon steel and stainless steel components exposed to an exhaust gas environment.

The project team found that, based on the information discussed above, the applicant has met the criteria of SRP-LR Section 3.3.2.2.7.3 for further evaluation. The project team found that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

A7.3.2.2.2.6 Loss of Material Due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion (MIC)

A7.3.2.2.2.6.1 Loss of Material Due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion (MIC) [Item 1]

The project team reviewed FRCT Table 3.6.1B, line item 3.3.1-19 against the criteria in SRP-LR Section 3.3.2.2.8.

SRP-LR Section 3.3.2.2.8 stated that loss of material due to general, pitting, crevice corrosion, and MIC could occur for steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil. The buried piping and tanks inspection program relies on industry practice, frequency of pipe excavation, and operating experience to manage the effects of loss of material from general, pitting, and crevice corrosion and MIC. The effectiveness of the buried piping and tanks inspection program should be verified to evaluate an applicant's inspection frequency and operating experience with buried components, ensuring that loss of material is not occurring.

In FRCT Table 3.6.1B, line item 3.3.1-19, the applicant addressed loss of material of carbon steel piping, and steel tank bottoms, due to general, pitting, crevice and MIC. The applicant stated that the buried piping inspection – FRCT aging management program, B.1.26A, will be used to manage the loss of material in carbon steel piping exposed to a soil environment. The buried piping inspection – FRCT aging management program includes preventive measures to mitigate corrosion and periodic inspection of external surfaces for loss of material to manage the effects of corrosion on the pressure-retaining capacity of piping in a soil (external) environment. Preventive measures are in accordance with standard industry practices for maintaining external coatings and wrappings

The applicant further stated that the Aboveground Steel Tanks – FRCT aging management program, B.1.21A, will be used to manage the loss of material in steel tank bottoms exposed to a soil environment. The Aboveground Steel Tanks – FRCT aging management program includes periodic internal UT inspections on the bottom of the outdoor steel main fuel oil tank supported by a earthen/concrete foundation.

The project team reviewed the applicant's Buried Piping Inspection – FRCT (AMP B.1.26A) and verified that this aging management program included activities that are adequate to manage the loss of material of carbon steel piping. The applicant was asked to confirm that, for each of the material/environment combinations for which the Buried Piping Inspection Program will be credited, at least one inspection has been, or will be performed during the 10-year period immediately prior to entering the extended period of operation.

The applicant stated that inspections will be performed during the 10-year period immediately prior to entering the license renewal period for the buried piping for which this AMP is credited. There have not been any inspections completed to date, and there have not been any identified failures of this buried piping since the unites went into operation.

The project team reviewed the applicant's response and determined that, in addition to a focused inspection to be performed within the 10-year period after entering the extended period of operation, an inspection would be performed during the 10-year period immediately prior to the period of extended operation that would provide objective evidence that the components were in acceptable condition and that no significant aging was present for these buried components. On this basis, the project team determined that the applicant's response was acceptable.

In addition, the project team reviewed the applicant's Aboveground Steel Tanks – FRCT program (AMP B.1.21A) and verified that this aging management program included activities that are adequate to manage the loss of material in steel tank bottoms. The project team determined that FRCT AMPs B.1.26A and B.1.21A will adequately manage the loss of material of carbon steel piping and steel tank bottoms exposed to a soil environment.

The project team found that, based on the information discussed above, the applicant has met the criteria of SRP-LR Section 3.3.2.2.8 for further evaluation.

A7.3.2.2.2.6.2 <u>Loss of Material Due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion (MIC) [Item 2]</u>

The project team reviewed Table 3.6.1D, line item 3.4.1-11 against the criteria in SRP-LR Section 3.4.2.2.5.1.

SRP-LR Section 3.4.2.2.5.1 stated that loss of material due to general, pitting and crevice corrosion, and MIC could occur in steel (with or without coating or wrapping) piping, piping components, piping elements and tanks exposed to soil. The buried piping and tanks inspection program relies on industry practice, frequency of pipe excavation, and operating experience to manage the effects of loss of material from general corrosion, pitting and crevice corrosion, and MIC. The effectiveness of the buried piping and tanks inspection program should be verified to evaluate an applicant's inspection frequency and operating experience with buried components, ensuring that loss of material is not occurring.

In its response to RAI 2.5.15-1, Appendix C, Table 3.6.1D, line item 3.4.1-11, the applicant stated that the new buried piping and tanks inspection – Met tower repeater engine fuel supply, B.1.26B, aging management program will be used to manage the loss of material in copper and carbon steel piping and carbon steel tanks in the repeater engine fuel supply system exposed to a soil environment. The buried piping and tanks inspection – Met tower repeater engine fuel supply aging management program includes the periodic inspection of external surfaces for loss of material to manage the effects of corrosion on the pressure-retaining capacity of piping and tanks exposed to a soil (external) environment. The external inspections of the buried piping and tank will occur opportunistically when excavated during maintenance or excavated and inspected for any other reason. Within 10 years prior to entering the period of extended operation, inspection of the buried piping and tank will be performed unless an opportunistic inspection occurs within this ten-year period.

Following commencement of the period of extended operation, inspection of the buried piping and tank will again be performed within the next ten years, unless an opportunistic Inspection occurs during this ten-year period. Based on meteorological tower repeater engine fuel supply operating experience, there have been no leaks in the underground portion of the propane piping and tank. Therefore the frequency of inspection, at least once in the 10 years prior to the period of extended operation and at least once in the first 10 years of extended operation, is adequate.

The program also includes preventive measures in with standard industry practices for the inspection and maintenance of external coatings and wrappings. Exceptions apply to the

NUREG-1 801 recommendations for buried piping and tanks inspection -Met tower repeater engine fuel supply aging management program implementation.

The project team reviewed the applicant's buried piping and tanks inspection – Met tower repeater engine fuel supply aging management program (AMP B.1.26B) and verified that this aging management program included activities that are adequate to manage the loss of material in copper and carbon steel piping and carbon steel tanks in the repeater engine fuel supply system exposed to a soil environment. On this basis, the project team determined that the applicant's AMP will adequately manage the loss of material of copper and carbon steel piping and carbon steel tank bottoms exposed to a soil environment.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.4.2.2.5.1 for further evaluation.

A7.3.2.2.2.7 <u>Loss of Material Due to General, Pitting, Crevice, Microbiologically Influenced Corrosion and Fouling</u>

A7.3.2.2.2.7.1 <u>Loss of Material Due to General, Pitting, Crevice, Microbiologically Influenced Corrosion and Fouling [Item 1]</u>

The project team reviewed FRCT Table 3.6.1B, line item 3.3.1-20 against the criteria in SRP-LR Section 3.3.2.2.9.1.

SRP-LR Section 3.3.2.2.9.1 stated that loss of material due to general, pitting, crevice, MIC, and fouling could occur for steel piping, piping components, piping elements, and tanks exposed to fuel oil. The existing aging management program relies on the fuel oil chemistry program for monitoring and control of fuel oil contamination to manage loss of material due to corrosion or fouling. Corrosion or fouling may occur at locations where contaminants accumulate. The effectiveness of the fuel oil chemistry control should be verified to ensure that corrosion is not occurring. The GALL Report recommended further evaluation of programs to manage loss of material due to general, pitting, crevice, MIC, and fouling to verify the effectiveness of the fuel oil chemistry program. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In FRCT Table 3.6.1B, line item 3.3.1-20, the applicant addressed loss of material in carbon steel and cast iron piping, piping components, piping elements, and tanks, due to general, pitting, crevice, MIC, and fouling. The applicant stated that the one-time inspection – FRCT aging management program, B.1.24A, will be used to verify the effectiveness of the Fuel Oil Chemistry – FRCT aging management program, B.1.22A, at managing the loss of material in carbon steel and cast iron piping, piping components, piping elements, and tanks exposed to a fuel oil environment. The One-Time Inspection – FRCT aging management program includes (a) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience; (b) identification of the inspection locations in the system or component based on the aging effect; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined; and (d) evaluation of the need for follow-up examinations to monitor the progression of aging if age related degradation is found that could jeopardize an intended function before the end of the period of extended operation.

The project team reviewed the applicant's fuel oil chemistry program – FRCT (AMP B.1.24A) and verified that this aging management program included activities that will mitigate loss of material in carbon steel and cast iron piping, piping components, piping elements, and tanks. In addition, the project team reviewed the applicant's One-Time Inspection Program (B.1.24) and verified that this aging management program included inspections to detect loss of material due to general, pitting, crevice, MIC, and fouling as a means of verifying the effectiveness of the fuel oil chemistry program – FRCT. The project team determined that these AMPs will adequately manage loss of material in carbon steel and cast iron piping, piping components, piping elements, and tanks exposed to a fuel oil environment.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.3.2.2.9.1 for further evaluation.

A7.3.2.2.2.7.2 Loss of Material Due to General, Pitting, Crevice, Microbiologically Influenced Corrosion and Fouling [Item 2]

The project team reviewed FRCT Table 3.6.1B, line item 3.3.1-21 against the criteria in SRP-LR Section 3.3.2.2.9.2.

SRP-LR Section 3.3.2.2.9.2 stated that loss of material due to general, pitting, crevice, MIC, and fouling could occur for steel heat exchanger components exposed to lubricating oil. The existing aging management program relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. However, control of lube oil contaminants may not always have been adequate to preclude corrosion. Therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion is not occurring. The GALL Report recommended further evaluation of programs to manage corrosion to verify the effectiveness of the lube oil program. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In FRCT Table 3.6.1B, line item 3.3.1-21, the applicant addressed loss of material in carbon steel heat exchanger components, due to general, pitting, crevice, MIC, and fouling. The applicant stated that the one-time inspection – FRCT aging management program, B.1.24A, will be used to verify the effectiveness of the Lubricating Oil Analysis Program – FRCT, B.1.39, at managing the loss of material in carbon steel heat exchanger components exposed to a lubricating oil environment. The One-Time Inspection – FRCT aging management program includes (a) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience; (b) identification of the inspection locations in the system or component based on the aging effect; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined; and (d) evaluation of the need for follow-up examinations to monitor the progression of aging if age related degradation is found that could jeopardize an intended function before the end of the period of extended operation.

The project team reviewed the applicant's Lubricating Oil Analysis Program – FRCT (AMP B.1.39) and verified that this aging management program included activities that will mitigate loss of material in carbon steel heat exchanger components. In addition, the project team reviewed the applicant's One-Time Inspection Program (B.1.24) and verified that this aging management program included inspections to detect loss of material due to general, pitting, crevice, MIC, and fouling as a means of verifying the effectiveness of the Lubricating Oil

Analysis Program – FRCT. The project team determined that these AMPs will adequately manage loss of material in carbon steel heat exchanger components exposed to a lubricating oil environment.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.3.2.2.9.2 for further evaluation.

A7.3.2.2.2.8 Loss of Material Due to Pitting and Crevice Corrosion

The project team reviewed FRCT Table 3.6.1B, line item 3.3.1-25 against the criteria in SRP-LR Section 3.3.2.2.10.3.

SRP-LR Section 3.3.2.2.10.3 stated that loss of material due to pitting and crevice corrosion could occur for copper alloy HVAC piping, piping components, and piping elements exposed to condensation (external). The GALL Report recommended further evaluation of a plant-specific aging management program to ensure that these aging effects are adequately managed.

In FRCT Table 3.6.1B, line item 3.3.1-25, the applicant addressed loss of material in copper alloy heat exchanger tubes, due to pitting and crevice corrosion. The applicant stated that the Periodic Inspection Program – FRCT, B.2.5A, will be used to manage the loss of material in copper alloy heat exchanger tubes exposed to a condensation (external) environment. The Periodic Inspection Program – FRCT will address systems in the scope of license renewal that require periodic monitoring of aging effects, and are not covered by other existing periodic monitoring programs. Activities will consist of a periodic inspection of selected systems and components to verify integrity and confirm the absence of identified aging effects. The inspections will be condition monitoring examinations, intended to assure that existing environmental conditions are not causing material degradation that could result in a loss of system intended functions.

The project team reviewed the applicant's Periodic Inspection Program – FRCT (AMP B.2.5A) and verified that this aging management program included activities that are adequate to manage loss of material in copper alloy heat exchanger tubes. The project team determined that FRCT AMP B.2.5A will adequately manage loss of material in copper alloy heat exchanger tubes exposed to a condensation (external) environment.

The project team found that, based on the information discussed above, the applicant has met the criteria of SRP-LR Section 3.3.2.2.10.3 for further evaluation.

A7.3.2.2.2.9 Loss of Material Due to Pitting, Crevice, and Microbiologically Influenced Corrosion

A7.3.2.2.2.9.1 Loss of Material Due to Pitting, Crevice, and Microbiologically Influenced Corrosion [Item 1]

The project team reviewed FRCT Table 3.6.1B, line item 3.3.1-32 against the criteria in SRP-LR Section 3.3.2.2.12.1.

SRP-LR Section 3.3.2.2.12.1 stated that loss of material due to pitting, crevice, and MIC could occur in stainless steel, aluminum, and copper alloy piping, piping components, and piping elements exposed to fuel oil. The existing aging management program relies on the fuel oil chemistry program for monitoring and control of fuel oil contamination to manage loss of material due to corrosion. However, corrosion may occur at locations where contaminants accumulate and the effectiveness of fuel oil chemistry control should be verified to ensure that corrosion is not occurring. The GALL Report recommended further evaluation of programs to manage corrosion to verify the effectiveness of the fuel oil chemistry control program. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In FRCT Table 3.6.1B, line item 3.3.1-32, the applicant addressed loss of material in stainless steel piping, piping components, and piping elements, due to pitting, crevice, and MIC. The applicant stated that the one-time inspection – FRCT aging management program, B.1.24A, will be used to verify the effectiveness of the Fuel Oil Chemistry – FRCT aging management program, B.1.22A, at managing the loss of material in stainless steel piping, piping components, and piping elements exposed to a fuel oil environment. The One-Time Inspection – FRCT aging management program includes (a) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience; (b) identification of the inspection locations in the system or component based on the aging effect; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined; and (d) evaluation of the need for follow-up examinations to monitor the progression of aging if age related degradation is found that could jeopardize an intended function before the end of the period of extended operation.

The project team reviewed the applicant's Fuel Oil Chemistry – FRCT program (AMP B.1.24) and verified that this aging management program included activities that will mitigate loss of material due to pitting, crevice, and MIC. In addition, the project team reviewed the applicant's One-Time Inspection Program (B.1.24) and verified that this aging management program included inspections to detect loss of material due to pitting, crevice, and MIC as a means of verifying the effectiveness of the Fuel Oil Chemistry – FRCT program. The project team determined that these AMPs will adequately manage loss of material in stainless steel piping, piping components, and piping elements exposed to a fuel oil environment.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.3.2.2.12.1 for further evaluation.

A7.3.2.2.2.9.2 <u>Loss of Material Due to Pitting, Crevice, and Microbiologically Influenced Corrosion [Item 2]</u>

The project team reviewed FRCT Table 3.6.1B, line item 3.3.1-33 against the criteria in SRP-LR Section 3.3.2.2.12.2.

SRP-LR Section 3.3.2.2.12.2 stated that loss of material due to pitting, crevice, and MIC could occur in stainless steel piping, piping components, and piping elements exposed to lubricating oil. The existing program relies on the periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. However, control of lube oil contaminants may not always have been adequate to preclude corrosion. Therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion is not occurring. The GALL Report recommended further evaluation of programs to manage corrosion to verify the effectiveness of the lubricating oil program. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In FRCT Table 3.6.1B, line item 3.3.1-33, the applicant addressed loss of material in stainless steel piping, piping components, and piping elements, due to pitting, crevice, and MIC. The applicant stated that the One-Time Inspection – FRCT aging management program, B.1.24A, will be used to verify the effectiveness of the Lubricating Oil Analysis Program – FRCT, B.1.39, at managing the loss of material in stainless steel piping, piping components, and piping elements exposed to a lubricating oil environment. The One-Time Inspection – FRCT aging management program includes (a) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience; (b) identification of the inspection locations in the system or component based on the aging effect; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined; and (d) evaluation of the need for follow-up examinations to monitor the progression of aging if age related degradation is found that could jeopardize an intended function before the end of the period of extended operation.

The project team reviewed the applicant's Lubricating Oil Analysis Program – FRCT(AMP B.1.39) and verified that this aging management program included activities that will manage the loss of material in stainless steel piping, piping components, and piping elements. In addition, the project team reviewed the applicant's One-Time Inspection – FRCT aging management program (B.1.24A) and verified that this aging management program included inspections to detect loss of material due to due to pitting, crevice, and MIC as a means of verifying the effectiveness of the Lubricating Oil Analysis Program – FRCT. The project team determined that these AMPs will adequately manage loss of material in stainless steel piping, piping components, and piping elements exposed to a lubricating oil environment.

The project team found that, based on the above discussion, the applicant has met the criteria of SRP-LR Section 3.3.2.2.12.2 for further evaluation.

Conclusion

On the basis of its review, for component groups evaluated in the GALL Report for which the GALL Report recommended further evaluation, the project team determined that the applicant adequately addressed the issues that were further evaluated.

A7.3.2.2.3 *AMR Results That Are Not Consistent With The GALL Report Or Not Addressed In The GALL Report*

Summary of Information in the Application

In applicant's supplemental response to RAI 2.5.1.19-1, Appendix C, Table 3.6.1B, Summary of Aging Management Evaluations for the FRCT Mechanical Systems, the applicant provided information regarding components or material/environment combinations in the GALL Report that it evaluated and identified as not applicable to its plant.

In applicant's supplemental response to RAI 2.5.1.19-1, Appendix C, Table 3.6.2.1.2B, the applicant provided additional details of the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that are not consistent with the GALL Report. Specifically, the applicant indicated, via Notes F through J, that neither the identified component nor the material/environment combination is evaluated in the GALL Report and provided information concerning how the aging effect requiring management will be managed.

Project Team Evaluation

The project team reviewed the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that are not consistent with the GALL Report or are not addressed in the GALL Report.

A7.3.2.2.3.1 Mechanical System AMR Line Items That Have No Aging Effect (Table 3.6.2.1.2B)

In its supplemental response to RAI 2.5.1.19-1, Appendix C, Table 3.6.2.1.2B, the applicant included AMR line-items for which no aging effects were identified as a result of its aging management review process. Specifically, instances in which the applicant stated that no aging effects were identified occurred for components fabricated from stainless steel and aluminum exposed to indoor air; glass exposed to outdoor air; galvanized steel exposed to indoor air, steel or stainless steel exposed to concrete, and glass exposed to closed-cycle cooling water.

The project team reviewed the recommendations in the GALL Report for these material/environment combinations, and determined that the applicant's evaluations are consistent with the recommendations in the GALL Report. In addition, the project team reviewed the applicant's AMR technical basis document, OC-AMR-2.5.1, ?Station Blackout System – Mechanical," Rev. 0, which includes an operating experience review for the FRCT, and determined that no significant aging effects were identified for FRCT mechanical components with these material/environment combinations.

On the basis of its review of current industry research and operating experience, the project team found that stainless steel and aluminum exposed to indoor air, glass exposed to outdoor air, and glass exposed to closed-cycle cooling water will not result in aging that will be of concern during the period of extended operation. Therefore, the project team determined that there are no applicable aging effects requiring management for these material/environment combinations.

A7.3.2.2.3.2 Loss of Preload for Carbon and Low Allow Steel Exposed to Outdoor Air (External) (FRCT Table 3.6.2.1.2B)

In its supplemental response to RAI 2.5.1.19-1, Appendix C, Table 3.6.2.1.2B, the applicant included AMR line-items for loss of preload for closure bolting constructed of carbon and low alloy steel exposed to outdoor air (external). The applicant credited the Bolting Integrity – FRCT program (AMP B.1.12A) to manage this aging effect. Generic note H was noted indicating that the aging effect is not addressed in the GALL Report for this component, material and environment combination. In plant specific note 2 to Table 3.6.2.1.2B, the applicant stated that the aging effects for carbon and alloy steel closure bolting in an outdoor air (external) environment also include loss of preload.

The project team reviewed the applicant's Bolting Integrity – FRCT program (AMP B.1.12A) and determined that this program includes activities to manage loss of preload for closure bolting constructed of carbon and low alloy steel exposed to outdoor air (external). On this basis, the project team determined that the applicants aging management review is acceptable.

A7.3.2.2.3.3 Loss of Preload for Stainless Steel Exposed to Indoor or Outdoor Air (External) (FRCT Table 3.6.2.1.2B)

In its supplemental response to RAI 2.5.1.19-1, Appendix C, Table 3.6.2.1.2B, the applicant included AMR line-items for loss of preload for closure bolting constructed of stainless steel exposed to indoor or outdoor air (external). The applicant credited the Bolting Integrity – FRCT program (AMP B.1.12A) to manage this aging effect. Generic note G was noted indicating that the environment is not addressed in the GALL Report for this component and material combination. In plant specific note 7 to Table 3.6.2.1.2B, the applicant stated that the aging effects for stainless steel closure bolting in an outdoor air (external) environment also include loss of material and loss of preload.

The project team reviewed the applicant's Bolting Integrity – FRCT program (AMP B.1.12A) and determined that this program includes activities to manage loss of preload for closure bolting constructed of stainless steel exposed to indoor or outdoor air (external). On this basis, the project team determined that the applicants aging management review is acceptable.

A7.3.2.2.3.4 Cracking Initiation and Growth for Carbon and Low Allow Steel Exposed to Combustion Turbine Exhaust Gases (Internal) (FRCT Table 3.6.2.1.2B)

In its supplemental response to RAI 2.5.1.19-1, Appendix C, Table 3.6.2.1.2B, the applicant included AMR line-items for cracking initiation and growth for the combustion turbine casing constructed of carbon and low alloy steel exposed to exhaust gases (internal). The applicant credited the periodic inspection – FRCT program (AMP B.2.5A) to manage this aging effect. Generic note H was noted indicating that the aging effect is not addressed in the GALL Report for this component, material and environment combination. In plant specific note 9 to Table 3.6.2.1.2B, the applicant stated that the combustion turbine casing and exhaust plenum (duct) are inspected for cracking during maintenance inspections. Cracks have been found in the past. Some cracks have resulted in leaks, but have not prevented combustion turbine operation. Cracks are repaired prior to reassembly.

The project team reviewed the applicant's periodic inspection – FRCT program (AMP B.2.5A) and determined that this program includes activities to manage cracking initiation and growth for the combustion turbine casing constructed of carbon and low alloy steel exposed to exhaust gases (internal). On this basis, the project team determined that the applicants aging management review is acceptable.

A7.3.2.2.3.5 Reduction of Heat Transfer for Carbon and Low Allow Steel Exposed to Fuel Oil (Internal) (FRCT Table 3.6.2.1.2B)

In its supplemental response to RAI 2.5.1.19-1, Appendix C, Table 3.6.2.1.2B, the applicant included AMR line-items for reduction of heat transfer for the electric heater (fuel forwarding skid) constructed of carbon and low alloy steel exposed to fuel oil (internal). The applicant credited the Fuel Oil Chemistry – FRCT program (AMP B.1.22A) and the One-Time Inspection – FRCT program (AMP B.1.24A) to manage this aging effect. Generic note H was noted indicating that the aging effect is not addressed in the GALL Report for this component, material and environment combination. In plant specific note 4 to Table 3.6.2.1.2B, the applicant stated that aging effects include reduction of heat transfer between the fuel oil environment and steel-sheathed tubular heating elements.

The project team reviewed the applicant's Fuel Oil Chemistry – FRCT program (AMP B.1.22A) and determined that this program includes activities to manage reduction of heat transfer for the electric heater (fuel forwarding skid) constructed of carbon and low alloy steel exposed to fuel oil (internal). In addition, the project team reviewed the applicant's One-Time Inspection – FRCT program (AMP B.1.24A) and determined that this program includes inspections that are adequate to verify the effectiveness of the Fuel Oil Chemistry – FRCT program. On this basis, the project team determined that the applicants aging management review is acceptable.

A7.3.2.2.3.6 Change in Material Properties for Elastomer Exposed to Fuel Oil or Outdoor Air (External) (FRCT Table 3.6.2.1.2B)

In its supplemental response to RAI 2.5.1.19-1, Appendix C, Table 3.6.2.1.2B, the applicant included AMR line-items for change of material properties for expansion joints and flexible connections constructed of elastomer (fuel oil system) exposed to fuel oil or outdoor air (external). The applicant credited the periodic inspection – FRCT program (AMP B.2.5A) to manage this aging effect. Generic note G was noted indicating that the environment is not addressed in the GALL Report for this component and material combination.

The project team reviewed the applicant's periodic inspection – FRCT program (AMP B.2.5A) and determined that this program includes activities to manage change of material properties for expansion joints constructed of elastomer (fuel oil system) exposed to fuel oil or outdoor air (external). On this basis, the project team determined that the applicants aging management review is acceptable.

A7.3.2.2.3.7 Reduction of Heat Transfer and Loss of Material for Copper Exposed to Indoor or Outdoor Air (External) (FRCT Table 3.6.2.1.2B)

In its supplemental response to RAI 2.5.1.19-1, Appendix C, Table 3.6.2.1.2B, the applicant included AMR line-items for reduction of heat transfer and loss of material for heat exchangers (cooling tower) constructed of copper (tubes) exposed to indoor or outdoor air (external). The applicant credited the periodic inspection – FRCT program (AMP B.2.5A) to manage this aging effect. Generic note G was noted indicating that the environment is not addressed in the GALL Report for this component and material combination. In plant specific note 8 to Table 3.6.2.1.2B, the applicant stated that visual inspection of tubes and fins using the identified AMP will assure that the heat transfer intended function is maintained.

The project team reviewed the applicant's periodic inspection – FRCT program (AMP B.2.5A) and determined that this program includes activities to manage reduction of heat transfer and loss of material for heat exchangers (cooling tower) constructed of copper (tubes) exposed to indoor or outdoor air (external). On this basis, the project team determined that the applicants aging management review is acceptable.

A7.3.2.2.3.8 Loss of Material for Bronze Exposed to Outdoor Air (External) (FRCT Table 3.6.2.1.2B)

In its supplemental response to RAI 2.5.1.19-1, Appendix C, Table 3.6.2.1.2B, the applicant included AMR line-items for loss of material for valve bodies constructed of bronze exposed to outdoor air (external). The applicant credited the structures monitoring program (AMP B.1.31) to manage this aging effect. Generic note G was noted indicating that the environment is not addressed in the GALL Report for this component and material combination.

The project team reviewed the applicant’s structures monitoring program (AMP B.1.31) and determined that this program includes activities to manage loss of material for valve bodies constructed of bronze exposed to outdoor air (external). On this basis, the project team determined that the applicants aging management review is acceptable.

A7.3.2.2.3.9 Loss of Material for Copper Exposed to Soil (Radio Communications Systems Table 3.6.2.1.3)

In its response to RAI 2.5.1.15-1, Appendix C, Table 3.6.2.1.3, the applicant included AMR line-items for loss of material for piping and fittings constructed of copper exposed to soil. The applicant credited the buried piping and tanks inspection-Met tower repeater engine fuel supply program (AMP B.1.26B) to manage this aging effect. Generic note G was noted indicating that the environment is not addressed in the GALL Report for this component and material combination.

The project team reviewed the applicant’s buried piping and tanks inspection-Met tower repeater engine fuel supply program (AMP B.1.26B) and determined that this program includes activities to manage loss of material for piping and fittings constructed of copper exposed to soil. On this basis, the project team determined that the applicants aging management review is acceptable.

A7.3.2.2.3.10 Loss of Material for Copper Exposed to Outdoor Air (Radio Communications Systems Table 3.6.2.1.3)

In its response to RAI 2.5.1.15-1, Appendix C, Table 3.6.2.1.3, the applicant included AMR line-items for loss of material for piping and fittings constructed of copper exposed to outdoor air (external). The applicant credited the structures monitoring program (AMP B.1.31) to manage this aging effect. Generic note G was noted indicating that the environment is not addressed in the GALL Report for this component and material combination.

The project team reviewed the applicant’s structures monitoring program (AMP B.1.31) and determined that this program includes activities to manage loss of material for piping and fittings constructed of copper exposed to outdoor air (external). On this basis, the project team determined that the applicants aging management review is acceptable.

A7.3.2.2.3.11 Loss of Material for Brass Exposed to Outdoor Air (Radio Communications Systems Table 3.6.2.1.3)

In its response to RAI 2.5.1.15-1, Appendix C, Table 3.6.2.1.3, the applicant included AMR line-items for loss of material for valve bodies constructed of brass exposed to outdoor air (external). The applicant credited the structures monitoring program (AMP B.1.31) to manage this aging effect. Generic note G was noted indicating that the environment is not addressed in the GALL Report for this component and material combination.

The project team reviewed the applicant’s structures monitoring program (AMP B.1.31) and determined that this program includes activities to manage loss of material for valve bodies constructed of brass exposed to outdoor air (external). On this basis, the project team determined that the applicants aging management review is acceptable.

Conclusion

On the basis of its review, the project team found that the applicant appropriately evaluated AMR results involving material, environment, aging effects requiring management, and AMP combinations that are not addressed in the GALL Report.

A7.3.2.3 Conclusion

On the basis of its review, the project team determined that the applicant has demonstrated that the aging effects associated with the FRCT mechanical system components will be adequately managed.

The project team also reviewed the applicable UFSAR supplement program summaries and concluded that they adequately describe the AMPs credited for managing aging of the FRCT mechanical system components, as required by 10 CFR 54.21(d).

A7.3.3 Aging Management of Structural Components for FRCT and Meteorological Tower

This section of the audit and review report documents the project team's review and evaluation of the aging management review (AMR) results for the structural components of the FRCT (Station Blackout System) and the Meteorological Tower associated with the Radio Communication System.

A7.3.3.1 Summary of Technical Information in the Application

The applicant provided the results of its AMRs for the structural components of the FRCT in its initial response to RAI 2.5.1.19-1, dated 10/12/05. For the FRCT structural components, the Table 1 entries and the Table 2 entries are in Appendix C of the applicant's response: Supplemental Table 3.6.1C, ?Summary of Aging Management Evaluations for the Station Blackout System-Structural," and Supplemental Table 3.6.2.1.2C, ?Station Blackout System Structural Components, Summary of Aging Management Evaluation."

The applicant provided the results of its AMRs for the structural components of the meteorological tower in its response to RAI 2.5.1.15-1, dated 12/09/05. For the meteorological tower structural components, the AMR Summary, the Table 1 entries and the Table 2 entries are in Appendix C of the applicant's response: New Summary Section 3.5.2.1.20, Meteorological Tower Structures; New Oyster Creek LRA Table 1, Table 3.6.1D Summary of Aging Management Evaluations; New Oyster Creek LRA Table 2, Table 3.5.2.1.20, Meteorological Tower Structures.

A7.3.3.2 Project Team Evaluation

The project team reviewed the applicant's initial response to RAI 2.5.1.19-1, Appendix C, and it's response to RAI 2.5.1.15-1, Appendix C, to determine if the applicant provided sufficient information to demonstrate that the effects of aging for the FRCT and meteorological tower structural components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The project team reviewed those AMR line-items that the applicant claimed are consistent with the GALL Report, and for which no further evaluation is recommended. The project team did not repeat its review of the matters described in the GALL Report. However, the project team did verify that the material presented in the applicant's responses to RAI 2.5.1.19-1, Appendix C, and RAI 2.5.15-1, Appendix C, was applicable and that the applicant had identified the appropriate GALL Report AMR line-items. The project team's audit evaluation is documented in Section A7.3.3.2.1.

The project team also reviewed those AMR line-items for which further evaluation is recommended by the GALL Report. The project team confirmed that the applicant's further evaluations were in accordance with the acceptance criteria in the SRP-LR. The project team's audit evaluation is documented in Section A7.3.3.2.2.

The project team also reviewed the remaining AMR line-items that were not consistent with or not addressed in the GALL Report. The project team's audit evaluation is documented in Section A7.3.3.2.3.

The project team also reviewed the AMP summary description of the structures monitoring program (B.1.31) in the UFSAR Supplement, to ensure that it provided an adequate description of the program credited with managing aging for the structural components.

Table A7.3.3-1 below provides a summary of the project team's evaluation of the components, aging effects/aging mechanisms, and AMPs listed in the applicant's responses to RAI 2.5.1.19-1 and 2.5.1.15-1, that are addressed in the GALL Report. It also includes the section of this Attachment to the audit and review report in which the project team's evaluation is documented.

Table A7.3.3-1 Evaluation for FRCT, Radio Communications Systems, and Met Tower Structural System Components in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Project Team Evaluation
Steel closure bolting exposed to air – indoor uncontrolled (external)	Loss of material due to general, pitting and crevice corrosion, loss of preload due to stress relaxation	Bolting Integrity	Structures Monitoring (B.1.31)	Acceptable since the OCGS structures monitoring program is consistent with the recommendations in the GALL bolting integrity program for this component group/aging effect combination (See Audit Report Section A7.3.2.2.1.3)
Steel bolting exposed to air – outdoor (external)	Loss of material due to general, pitting and crevice corrosion	Bolting Integrity	Structures Monitoring (B.1.31)	Acceptable since the OCGS structures monitoring program is consistent with the

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Project Team Evaluation
				recommendations in the GALL bolting integrity program for this component group/aging effect combination (See Audit Report Section A7.3.2.2.1.3)
Elastomer fire barrier penetration seals exposed to air – outdoor or air – indoor uncontrolled	Increased hardness, shrinkage and loss of strength due to weathering	Fire Protection	Structures Monitoring (B.1.31)	Acceptable since the OCGS structures monitoring program is consistent with the GALL fire protection program for this component group/ aging effect combination (See Audit Report Section A7.3.2.2.1.1)
Galvanized steel piping, piping components, and piping elements exposed to air – indoor uncontrolled	None	None	None	Consistent with GALL (See Audit Report Section A7.3.3.2.3.1)
Steel and stainless steel piping, piping components, and piping elements in concrete	None	None	None	Consistent with GALL (See Audit Report Section A7.3.3.2.3.1)
All Groups except Group 6: accessible and inaccessible interior/exterior concrete, steel & Lubrite components	All types of aging effects	Structures Monitoring	Structures Monitoring Program (B.1.31)	Consistent with GALL (See Section A7.3.3.2.1)
All Groups except Group 6: interior and above grade exterior concrete	Cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring Program	Structures Monitoring Program (B.1.31)	Consistent with GALL (See Section A7.3.3.2.1)
All Groups except Group 6: steel components: all structural steel	Loss of material due to corrosion	Structures Monitoring Program. If protective coatings are relied upon to manage the effects of aging, the	Structures Monitoring Program (B.1.31)	Consistent with GALL (See Section A7.3.3.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Project Team Evaluation
		structures monitoring program is to Include provisions to address protective coating monitoring and maintenance.		
All Groups except Group 6: accessible and inaccessible concrete: foundation	Loss of material (spalling, scaling) and cracking due to freeze- thaw	Structures Monitoring Program. Evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index >100 day-inch/yr) (NUREG-1557).	Structures Monitoring Program (B.1.31)	Consistent with GALL (See Section A7.3.3.2.1)
All Groups except Group 6: accessible and inaccessible interior/exterior concrete	Cracking due to expansion due to reaction with aggregates	Structures Monitoring Program. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R-77.	Structures Monitoring Program (B.1.31)	Consistent with GALL (See Section A7.3.3.2.1)
Groups 1-3, 5-9: All	Cracks and distortion due to increased stress levels from settlement	Structures Monitoring Program. If a de-watering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Structures Monitoring Program (B.1.31)	Consistent with GALL (See Section A7.3.3.2.1)
All Groups: support members: anchor bolts, concrete surrounding anchor bolts, welds, grout pad, bolted connections, etc.	Aging of component supports	Structures Monitoring	Structures Monitoring Program (B.1.31)	Consistent with GALL (See Section A7.3.3.2.1)
Support members; welds; bolted connections; support anchorage to building structure	Loss of material due to general and pitting corrosion	Structures Monitoring Program	Structures Monitoring Program (B.1.31)	Consistent with GALL (See Section A7.3.3.2.1)
Building concrete at locations of expansion and grouted anchors;	Reduction in concrete anchor capacity due to local concrete	Structures Monitoring Program	Structures Monitoring Program (B.1.31)	Consistent with GALL (See Section A7.3.3.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Project Team Evaluation
grout pads for support base plates	degradation/ service induced cracking or other concrete aging mechanisms			
Vibration isolation elements	Reduction or loss of isolation function/ radiation hardening, temperature, humidity, sustained vibratory loading	Structures Monitoring Program	Structures Monitoring Program (B.1.31)	Consistent with GALL (See Section A7.3.3.2.1)
Groups B2, and B4: galvanized steel, aluminum, stainless steel support members; welds; bolted connections; support anchorage to building structure	Loss of material due to pitting and crevice corrosion	Structures Monitoring Program	Structures Monitoring Program (B.1.31)	Consistent with GALL (See Section A7.3.3.2.1)

A7.3.3.2.1 AMR Results That Are Consistent with The GALL Report

Summary of Information in the Application

For aging management evaluations that the applicant stated are consistent with the GALL Report, the project team conducted its audit and review to determine if the applicant’s reference to the GALL Report in the OCGS LRA is acceptable.

The applicant identified the structures monitoring program (B.1.31) to manage the aging effects related to the FRCT and meteorological tower structural components, for all the consistent-with-GALL structural AMR line items. The project team’s evaluation of the structures monitoring program (B.1.31) is documented in Section 3.0.3 of this audit report.

Project Team Evaluation

The project team reviewed its assigned AMR line-items to determine that the applicant (1) provides a brief description of the system, components, materials, and environment; (2) states that the applicable aging effects have been reviewed and are evaluated in the GALL Report; and (3) identifies those aging effects for the structural system components that are subject to an AMR.

Conclusion

The project team has evaluated the applicant's claim of consistency with the GALL Report. The project team also has reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the project team found that the AMR results which the applicant claimed to be consistent with the GALL Report are consistent with the AMRs in the GALL Report.

A7.3.3.2.2 AMR Results For Which Further Evaluation Is Recommended By The GALL Report

Summary of Information in the Application

The project team noted that there are no AMR line items for structural components, for which the GALL Report recommends further evaluation, provided the structures monitoring program is credited. The applicant has credited the structures monitoring program; therefore, there are no applicable further evaluations.

A7.3.3.2.3 AMR Results That Are Not Consistent With The GALL Report Or Not Addressed In The GALL Report

Summary of Information in the Application

The applicant did not include any components or material/environment combinations in the GALL Report that it evaluated and identified as not applicable to its plant.

In the applicant's Supplemental Table 3.6.2.1.2C for the FRCT, and in Table 3.5.2.1.20 for the meteorological tower the applicant provided additional details of the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that are not consistent with the GALL Report. Specifically, the applicant indicated, via Notes F through J, that neither the identified component nor the material/environment combination is evaluated in the GALL Report and provided information concerning how the aging effect requiring management will be managed.

Project Team Evaluation

The project team reviewed the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that are not consistent with the GALL Report or are not addressed in the GALL Report.

A7.3.3.2.3.1 Structural AMR Line Items That Have No Aging Effect

In its response to RAI 2.5.1.19-1, Appendix C, Table 3.6.2.1.2C, and its response to RAI-2.5.15-1, Appendix C, Table 3.6.1D, the applicant included AMR line-items for which no aging effects were identified as a result of its aging management review process. The project team reviewed these AMR line items to determine their acceptability. They are:

- components fabricated from galvanized steel exposed to air-indoor uncontrolled
- components fabricated from steel and stainless steel exposed to concrete
- components fabricated from steel, stainless steel, aluminum, and copper alloy exposed to gas.

The project team reviewed the recommendations in the GALL Report for these material/environment combinations, and determined that the applicant's evaluations are consistent with the recommendations in the GALL Report. In addition, the project team reviewed the applicant's AMR technical basis document, OC-AMR-2.5.1, ?Station Blackout System-Structural," Rev. 0, and OC-AMR-2.5.1.15, ?Radio Communication System," Rev. 0, which included an operating experience review for the FRCT and Met tower, respectively, and determined that no significant aging effects were identified for structural components with these material/environment combinations.

On the basis of its review of current industry research and plant-specific operating experience, the project team found that galvanized steel exposed to air-indoor uncontrolled, steel and stainless steel exposed to concrete, and steel, stainless steel, aluminum, and copper alloy exposed to gas will not result in aging that will be of concern during the period of extended operation. Therefore, the project team determined that there are no applicable aging effects requiring management for these material/environment combinations.

A7.3.3.2.3.2 Change in Material Properties and Loss of Material for Wood Exposed to Soil (FRCT Table 3.6.2.1.2C)

In its response to RAI 2.5.1.19-1, Appendix C, Table 3.6.2.1.2C, the applicant included AMR line-items for change in material properties and loss of material for piles constructed of wood (creosote treated) exposed to soil. The applicant credited the structures monitoring program (AMP B.1.31) to manage these aging effects. Generic note J was noted indicating that neither the component, nor the material and environment combination is evaluated in the GALL Report. In plant specific note 2 to Table 3.6.2.1.2C, the applicant stated that the foundation piles are inaccessible and will not be directly inspected. Instead the foundation will be visually inspected for cracking and distortion due to increased stress levels from settlement that may result from degradation of the piles.

The project team asked the applicant to describe the operating experience and any history of degradation for the wood piles and the foundation that they support. The applicant indicated that the wooden piles are inaccessible, but the turbine support foundation has not shown signs of cracking or distortion due to increased stress levels from settlement that could result from degradation of the wooden piles. The project team determined that monitoring the foundation for settlement damage is an acceptable method to indirectly manage aging of the wood piles.

A7.3.3.2.3.3 Loss of Preload for Galvanized Steel Bolts Exposed to Outdoor Air (FRCT Table 3.6.2.1.2C)

In its response to RAI 2.5.1.19-1, Appendix C, Table 3.6.2.1.2C, the applicant included AMR line-items for loss of preload for structural bolts constructed of galvanized steel exposed to outdoor air. The applicant credited the structures monitoring program (AMP B.1.31) to manage this aging effect. Generic note H was noted indicating that the aging effect is not in the GALL Report for this component, material and environment combination. In plant specific note 3 to Table 3.6.2.1.2C, the applicant stated that the structures monitoring program is the applicable aging management program for this component.

The project team determined that the structures monitoring program (AMP B.1.31) is the appropriate aging management program, and concurred with the applicant's AMR for structural bolts constructed of galvanized steel exposed to outdoor air.

A7.3.3.2.3.4 Loss of Material for Carbon and Low Alloy Steel Exposed to Closed Cooling Water (FRCT Table 3.6.2.1.2C)

In its response to RAI 2.5.1.19-1, Appendix C, Table 3.6.2.1.2C, the applicant included an AMR line-item for loss of material for the supports for combustion turbines (skid, turbine support legs), constructed of carbon and low alloy steel, exposed to closed cooling water (internal). In plant specific note 1 to Table 3.6.2.1.2C, the applicant stated that the combustion turbine support legs are provided with a water jacket through which cooling water is circulated to minimize thermal expansion and to assist in maintaining alignment between the turbine and the generator. The applicant initially did not credit an aging management program.

The project team asked the applicant to provide information related to operating experience for the water-jacketed combustion turbine support legs, and to describe the aging management program that is credited for the interior (wetted) surfaces of the support legs, since note 1 states that the AMP will be provided later. The project team also asked if the scope of the selected AMP has been enhanced to identify the FRCT support legs.

In response, the applicant indicated that the combustion turbine support legs are structural members designed with an internal section that allows cooling water to flow through the inside of the support. Adequate cooling is demonstrated by the combustion turbine ability to maintain proper alignment. There is no operating experience that indicates degrading structural or heat transfer functions of these support legs. The water-cooled turbine support legs are identified as "Heat Exchangers (Support Leg)" in Table 3.6.2.1.2B that was submitted in the November 11, 2005, supplemental response to RAI 2.5.1.19-1. This table indicates that the Closed-Cycle Cooling Water System – FRCT (B.1.14A) aging management program is credited for managing the reduction of heat transfer and loss of material aging effects on the internal wetted surfaces. These components have been included in this AMP. See Table 5.2 of program basis document AMP-PBD-B.1.14A.

The project team confirmed that this component has been included in Closed-Cycle Cooling Water System – FRCT (B.1.14A), and that the program is appropriate for managing this aging effect.

A7.3.3.2.3.5 Change in Material Properties for Polyvinyl Chloride Exposed to Outdoor Air (Met Tower Table 3.5.2.1.20)

In its response to RAI 2.5.1.15-1, Appendix C, Table 3.5.2.1.20, the applicant included AMR line-items for change in material properties for conduits constructed of polyvinyl chloride exposed to outdoor air. The applicant credited the structures monitoring program (AMP B.1.31) to manage these aging effects. Generic note J was noted indicating that neither the component, nor the material and environment combination is evaluated in the GALL Report.

The project team determined that the structures monitoring program (AMP B.1.31) is the appropriate aging management program, and concurred with the applicant's AMR for conduits constructed of polyvinyl chloride exposed to outdoor air.

A7.3.3.2.3.6 No Aging Effect for Polyvinyl Chloride Exposed to Soil (Met Tower Table 3.5.2.1.20)

In its response to RAI 2.5.1.15-1, Appendix C, Table 3.5.2.1.20, the applicant included AMR line-items indicating no aging effect for conduits constructed of polyvinyl chloride exposed to soil. The applicant did not credit an aging management program. Generic note J was noted indicating that neither the component, nor the material and environment combination is evaluated in the GALL Report.

The project team noted that there has been extensive industrial application of and operating experience with polyvinyl chloride exposed to soil. This material is typically non-reactive with organic constituents in soil, and has seen wide use in buried applications. Therefore, the project team determined that the applicant's AMR for conduits constructed of polyvinyl chloride exposed to soil is acceptable.

A7.3.3.2.3.7 Loss of Material for Galvanized Steel Exposed to Soil (Met Tower Table 3.5.2.1.20)

In its response to RAI 2.5.1.15-1, Appendix C, Table 3.5.2.1.20, the applicant included AMR line-items for loss of material for conduits constructed of galvanized steel exposed to soil. The applicant credited the structures monitoring program (AMP B.1.31) to manage this aging effect. Generic note G was noted indicating that the environment is not addressed in the GALL Report for this component and material combination.

The project team determined that the structures monitoring program (AMP B.1.31) is the appropriate aging management program, and concurred with the applicant's AMR for conduits constructed of galvanized steel exposed to soil.

A7.3.3.2.3.8 Loss of Preload for Carbon and Low Alloy Steel Bolts Exposed to Outdoor Air (Met Tower Table 3.5.2.1.20)

In its response to RAI 2.5.1.15-1, Appendix C, Table 3.5.2.1.20, the applicant included AMR line-items for loss of preload for structural bolts constructed of carbon and low alloy steel exposed to outdoor air. The applicant credited the structures monitoring program (AMP B.1.31) to manage this aging effect. Generic note G was noted indicating that the environment is not addressed in the GALL Report for this component and material combination.

The project team determined that the structures monitoring program (AMP B.1.31) is the appropriate aging management program, and concurred with the applicant's AMR for structural bolts constructed of carbon and low alloy steel exposed to outdoor air.

Conclusion

On the basis of its review, the project team found that the applicant appropriately evaluated AMR results involving material, environment, aging effects requiring management, and AMP combinations that are not addressed in the GALL Report.

A7.3.3.3 Conclusion

On the basis of its review, the project team determined that the applicant has demonstrated that the aging effects associated with the FRCT and meteorological tower structural components will be adequately managed.

The project team also reviewed the applicable UFSAR supplement program summaries and concluded that they adequately describe the AMPs credited for managing aging of the FRCT and meteorological tower structural system components, as required by 10 CFR 54.21(d).